ONE J

Oil and Gas, Natural Resources, and Energy Journal

VOLUME 8 NUMBER 3

EVOLVING TRENDS IN PRODUCTION SHARING AGREEMENTS & COST RECOVERY SYSTEMS

EDUARDO G. PEREIRA, REG FOWLER, THOMAS STEPHENS, ALICIA ELIAS-ROBERTS, ANDRÉ LEMOS, WAN MOHD ZULHAFIZ WAN ZAHARI, REYHAN KAMIL & NURZHAN KAKIMOV*

Table of Contents

* See the Appendix for full biographical information on each author.

1. Introduction

Host nations tend to own and/or control the hydrocarbon resources situated in their own jurisdiction.[1] Although they can develop such resources by themselves, the high risks and costs involved encourage them to outsource such activities to investors, i.e., oil and gas companies.[2] The legal instruments behind such "outsourcing" procedures are commonly performed via a concession, license, lease, production sharing contract, service contract, or a hybrid form.[3] Although all of these instruments could lead to the same end "result," each instrument has its own characteristics.[4] The concession, license, and lease tend to confer full ownership of production on the investors while the host government gains royalties and/or taxation. The production sharing agreement tends to share the production. The service contract provides all the production to the host government, and the investor gets paid fees and reimbursed costs. So, one of the key distinctions between these agreements tends to be the ownership and costs involved. The agreements that provide higher amounts of production to the investor leaves them to cover their own costs whereas the agreements that provide higher amounts of production to the host nation allow certain costs to be recovered or compensated by the investor.

Cost recovery is an essential tool in a production-sharing system.[5] The investor will cover the upfront costs and risks of the upstream project.[6] However, the same investor will also be able to recover costs in accordance

1. Kim Talus and Eduardo Periera, *Introduction to Upstream Petroleum Law and Regulation*, OGEL 3 (2018).

2. *See generally* Eduardo G. Pereira, Cătălin-Gabriel Stănescu & Aaron Koenck, *Petroleum Concessions, Licenses and Leases: "Same-Same but Different?"* LSU J. OF ENERGY L. (2020) (outlining the material differences between oil and gas instruments).

3. *See* Eduardo Guedes Pereira et al., *Host Granting Instrument Models: Why Do They Matter and for Whom,* 6 Oil and Gas, Natural Res., and Energy J. 23 (2020).

4. *Id.*

5. Kirsten Bindemann, *Production Sharing Agreements: An Economic Analysis*, OXFORD INSTITUTE FOR ENERGY STUDIES (1999).

6. *See* Daniel Johnston, *International Petroleum Fiscal Systems and production sharing contracts* (1994); Tengku Nathan Machand, *The Indonesian Production Sharing Contract: An Investor Perspective,* KLUWER L. INT'L, HAGUE (2000).

with the rules defined in the production sharing contract (PSC). Such rules are detailed in the accounting procedure, which is an attachment to the PSC.[7] Costs are recovered by production through a schedule and details defined in the relevant PSC, but the investor should be careful before incurring costs if it is not certain whether they will be recovered.[8] At the same time, the host government is concerned about such costs because it may end up paying for them to the extent the investor reaches production and follows the rules defined in the PSC.[9] This is why the PSC contains a fairly complex and bureaucratic system in order to approve any cost as part of cost recovery.[10]

This paper analyses the challenges involved with cost recovery systems in nine case studies: Angola, Brazil, Ghana, Indonesia, Malaysia, Guyana, Trinidad and Tobago, and Kazakhstan. Following the analysis of the case studies, recommendations will be provided based on lessons learned and considerations prior to: (i) setting up a production-sharing regime, (ii) switching to a production-sharing regime, and (iii) modifying its current production-sharing regime.

2. Cost Recovery in PSCs

2.1. What is it and how does it work?

In a PSC, the international oil company (IOC),[11] at times referred to as the contractor, renders technical and financial services, and within the framework of the contract, undertakes and finances petroleum operations.[12] The IOC receives a certain percentage of the oil and gas produced as compensation for the work undertaken and a reasonable profit, while the state receives the other part. Thus, if no oil and gas is discovered in commercial quantities, those blocks explored cease to be a part of the contract area.[13] The IOC receives no compensation for all the work undertaken, and all its investments are simply written off.

---

7. *Id.*
8. *Id.*
9. *Id.*
10. *Id.*
11. Indonesia is the country really credited with this form of agreement and it was adopted in replacement of the system that existed beforehand, that is exclusive licenses, that was terminated by the government through Government Decree No. 44 of 26th October 1960.
12. Bernard Taverne, *An Introduction To The Regulation Of The Petroleum Industry: Laws, Contracts And Conventions,* 29 GEORGE WASHINGTON J. OF INT'L L. AND ECON. 2 (1994).
13. *Id.*

Bolivia and Indonesia adopted the PSC in the 1950s and 1960s, and since then, it has become a popular form of developing a country's resources.[14] In a PSC, the country grants the IOC a right to explore contractually specific areas for oil and gas, and upon discovery and subsequent production, the IOC recovers its costs of exploration and development. and thereafter, a profit. The IOC has the exclusive right to explore, search, drill for, produce, store, transport, and sell its share of petroleum produced. PSCs are the most common type of host-granting instrument (HGI) in the petroleum industry—especially among developing countries. As Smith et al. notes, "A primary objective of a PSC is to develop the host country's petroleum reserves, using the capital and technological expertise of the IOC while maintaining sovereignty and control of the reserves."[15]

PSCs were first introduced in Indonesia in 1966 in response to nationalistic sentiments which were running high as foreign companies and the concessions granted to them were evoking increasing criticism and hostility.[16] PSCs were introduced to ensure that ownership of the resource remained vested in the State. This model originated in Indonesia through its state oil company, Pertamina. The IOCs were not to be proprietors of the oil discovered as had been the case under the old arrangement but were merely contractors under the direction of the state. This direction was exercised through Pertamina, which exercised ownership of the nation's petroleum resources.[17] As noted by Gao, when Ibu Sutowo, the first President Director of Pertamina, took control of Indonesia's petroleum industry in 1966, he set forth five basic principles for any future agreement with IOCs:

1) The state oil company would have management control.
2) The contract would be based on production sharing instead of profit sharing.
3) The contractor (usually an IOC) would bear the pre-production risks and cost recovery would be limited to 40 percent of the annual production.

---

14. Indonesia is the country real credited with this form of agreement and it was adopted in replacement of the system that existed beforehand, that is exclusive licenses, that was terminated by the government through Government Decree No. 44 of 26th October 1960.

15. Ernest E. Smith et al., INT'L PETROL. TRANSACTIONS 471 (3d ed. 2010).

16. Kirsten Bindemann, PRODUCTION SHARING AGREEMENTS: AN ECONOMIC Analysis 10 (Oxford Institute for Energy Studies 1999).

17. Michael A. G Bunter, THE PROMOTION AND LICENSING OF PETROLEUM PROSPECTIVE ACREAGE 122 (Kluwer L. Int'l 2002).

4) The remainder of the production would be split 65/35 in favor of the State; and
5) Title to equipment purchased by the contractor would pass to the state oil company upon entry into Indonesia.[18]

PSCs are used in virtually all developing countries and they have found widespread acceptance. Countries that use the PSC include: Bangladesh, Cambodia, China, India, Indonesia, Laos, Malaysia, Mongolia, Myanmar, Vietnam, Nepal, Sri Lanka, Georgia, Kyrgyzstan, Kazakhstan, Russia, Turkmenistan, Uzbekistan, Azerbaijan, Belize, Nicaragua, Panama, Guatemala, Jamaica, Uruguay, Guyana, Cuba, Belize, Bahrain, Qatar, Oman, Iraq, Jordan, Syria, Yemen, Libya, Malta, Poland, Turkey, Albania, Uganda, Zambia, Madagascar, Liberia, Ethiopia, Libya, Egypt, Equatorial Guinea, Angola, Algeria, Cameroon, Congo, Egypt, Gabon, Gambia, Sudan, Kenya, Nigeria, Tanzania, Togo, and Zambia.

Kasekende and Ibrahim note that, "The type of agreement selected in an oil-producing country should ideally depend on three important parameters: the size of reserves, the exploration and production costs, and the recovery factor."[19] There is no standard or universal model of a PSC and each country that has adopted it has modified it to suit its own particular needs. However, it has certain basic features that make it able to be identified. A PSC aims to attract an IOC that is willing to invest financial and technological resources to explore its acreage, develop, and eventually produce petroleum in exchange for tangible and intangible benefits. In a standard PSC, the IOC bears all the risks of exploration. It typically finances all exploration and development costs and is often in charge of the operations and management of the field that is being explored and developed. If no oil or gas is found in commercial quantities, the IOC bears all the financial losses of the project. However, if oil and gas are discovered in commercial quantities, the IOC recoups its investments in kind from the crude oil and/or gas produced. This portion of the oil is often referred to as "cost recovery oil."

With respect to PSCs in general, the Contractor (usually an IOC) gets a share of production, which is usually in kind. The Contractor never holds title to the oil, and shares production risk with the government. Cost oil is deducted from net revenue (gross revenue after deduction of royalties). Cost recovery in PSCs boils down to deducting the costs incurred in the

18. Zhiguo Gao, INTERNATIONAL PETROLEUM CONTRACTS: CURRENT TRENDS AND NEW DIRECTIONS 68 (Graham and Trotman Ltd. 1st ed.1994).

19. Louis Kasekende & Elham M.A. Ibrahim, OIL AND GAS IN AFRICA 83 (Oxford University Press 2009).

exploration, development, and production operations—"cost oil." What is left thereafter is referred to as "Total Profit Oil." Total Profit of Oil is realized when Cost Oil is deducted from net revenue. Total Profit Oil is shared between the state and the Contractor on a contractually agreed basis defined in the PSC. Total Profit Oil is usually, but not always, taxable. Formulae for-profit oil sharing could be based on production (daily rate or absolute volume), Rate of Return (RoR), or R-Factors.

The main elements in a PSC are the royalty, cost recovery, or "cost oil," profit oil, and tax. Cost recovery is typically capped at an upper limit per annum and is not ad infinitum. It would include unrecovered costs from previous years, operating costs, expensed capital costs, current year depreciation, depletion, and amortization (DD&A), interest on financing, investment credit (uplift), and abandonment cost recovery fund. A 40% cost recovery would be considered on the low end and 70% on the upper end. The cost recovery provision stipulates that a sizeable percentage of the oil production goes to the oil company towards its past and current expenditures.

2.2. Is there any difference between cost recovery in PSCs and Risk Service Contracts?

Kasekende and Ibrahim note that "Risk service contracts seem to be dominant in countries with large reserves and low costs. Host countries with low costs and reserves tend to demand various levies to maximize the rent they can extract from oil."[20] They go on to note that "[p]roduction sharing arrangements dominate in countries with medium costs and large reserves."[21]

Risk Service contracts operate as agreements for the provision of service to the host country by the IOC for fees. The fees are subject to tax like profit oil in PSC.[22] In both PSCs and Risk service contracts, the IOC pays all the expenses at its own risk whether oil and gas is found or not. The contractor undertakes the risk of bearing all the costs of development and production, and the IOC is reimbursed for its costs and expenses only in the event of production. The IOC does not receive any payment unless it makes a commercial discovery and there is ensuing production. As for risk service contracts, once production is made by the Contractor, the Contractor is typically remunerated in cash. In exceptional circumstances, remuneration

---

20. *Id.*
21. *Id.*
22. Carole Nakhle, 4 PETROLEUM FISCAL REGIMES: EVOLUTION AND CHALLENGES (Routledge 2010); *accord* Philip Daniel, Michael Keen, & Charles McPherson, THE TAX'N OF PETROL. AND MINS.: PRINCIPLES, PROBLEMS AND PRACTICES 103 (Routledge 2010).

can be in the form of oil itself.[23] For PSCs, the Contractor is normally remunerated with barrels of oil. The IOC usually recovers the cost of investment in the development and production in agreed proportions before the sharing of crude oil with the host state.

The industry prefers PSC arrangements to Risk Service contracts. Service contracts tend to attract relatively little in investment capital, as returns on investment are considered low by IOCs. They are considered loss leaders with the hope of long-term constructive and profitable relationships with the host countries.[24]

2.3. Is there a difference between cost recovery in PSCs and tax deductions/allowances in Concession/License systems?

With respect to PSCs, the IOC will usually recover the cost of investments in petroleum operations in agreed proportions before the sharing of the oil with the host state—especially where the host state did not contribute to costs. In the concession/license system, the IOC is instead granted tax exemptions, reliefs, and rebates to cushion it against the costs. Thus, the essence of the tax concessions like in tax exemptions, rebate, and reliefs is to assist the IOCs to recover their cost of investments in the development and production of oil.

In its most basic form, cost recovery refers to a mechanism through which a contractor can recover most, if not all, of its capital and operating costs out of a specified percentage of production called 'cost recovery oil' when the project enters the production phase. Since parties can only recover their costs incurred if there is commercial discovery and subsequent production, there is an inherent risk in this mechanism for the contractor, whereas, with regards to tax deductions/allowances, the recovery of costs of investment is through capital allowances.

Generally, under the concession system, there is no recovery for the IOC's costs and expenses, as it owns the whole production except the royalty share. Under the PSC, the IOC recovers its costs and expenses from a share of the production which is allocated to cost recovery, subject to oversight by the host nation or its National Oil Company (NOC). Such cost recovery is only achievable if there is enough production in the first place. Concession agreements typically do not include cost recovery regimes like PSCs. In concession systems, the host country's general fiscal regime operates to impact cost recovery. Bonuses, royalties, taxes, allowances, and other fiscal

23. *Id.* at 102.
24. *Id.* at 104.

statutory obligations impact the hydrocarbon revenues and cash flows available to the IOC from which investment or project costs are recovered.[25]

The usual way of taxing oil companies operating within a concessionary regime is by a combination of income tax, a special petroleum tax, and royalties.[26] A notable difference between concession systems and PSCs is the structural design of the PSC regimes, which meticulously set out a portion of hydrocarbon production, or cost oil, to cover the IOC's costs. The cost oil provision limits cost recovery in any particular year.[27]

In a concessionary system, the IOC has a 100% entitlement to the hydrocarbons produced at the wellhead, except the portion for payment of royalties. Nakhle notes that in its basic form, a PSC has four main properties: royalty payments, cost oil, profit oil, and income taxes.[28] In the concessionary system, the IOC bears the costs and risks of exploration and development. It has no right to be paid if discovery and development do not occur. However, if discovery is made, the IOC is allowed to recover the cost it has incurred from the predetermined cost oil. Cost recovery is similar in concept to deductible expenses for tax purposes under the concessionary systems. It includes mainly unrecovered costs carried over from previous years, operating expenditures, capital expenditures, abandonment costs, and some investment incentives. Financing cost or interest, or interest expense, is generally not a recoverable cost, though unrecovered costs can often be rolled forward with an uplift in lieu of interest.[29]

2.4. What are the main challenges and concerns?

In general, the PSC is a contract that contains a financial formula showing how revenue is going to be apportioned between the IOC and the state. As noted earlier, it is mainly developing countries that use the PSC. Developed countries typically have a tax royalty system. Under any form of HGI (including the tax royalty and PSC), the more revenue that is generated, the more money each party gets. The PSC is purposely designed to incentivize the parties to maximize revenue.

A main challenge is that IOCs tend to be better resourced and experienced at focusing on ways to maximize PSC revenue, which in turn maximizes their own revenue. Most IOCs have an obligation to satisfy their funders or shareholders, which leads them to seek to minimize uncertainties of future

25. *Id*. at 95-98.
26. *Id.* at 94-95.
27. *Id.* at 99-101.
28. *See Id.*
29. Nakhle, *supra* note 22, at 99.

revenue in their contracts. Hence, they prefer the arrangements in a PSC, which is a long-term investment (typically 20 years or longer), to remain constant. As such, they seek to have a degree of certainty as to what share of PSC revenue will accrue to them. From the state's point of view, there may be other immediate pressures (for example, short-term budget constraints) that lead them to not be completely focused on maximizing revenue under the PSC. In some cases, the state may pursue such short-term interests under a particular PSC without factoring in the potential impact on future investments in that PSC, and potentially in other PSCs to be negotiated. An approach of pushing the boundaries of the PSC creates an inherent tension between maximizing revenue and attracting continued or new investments since the typical IOC preferentially allocates investments to countries that more closely adhere to the PSC (all else being equal). A typical IOC has multiple options, putting host states indirectly in competition with each other for investment by IOCs. Where revenue is not maximized under a PSC (or other form of HGI), both the IOC and state lose out. In extreme cases, a state may decide that it is not receiving sufficient revenue from the petroleum operations and may intervene to the extent that continued operations by the IOC become unviable; this was the case in Venezuela.

2.5. Current trends

Currently, in the Western world, traditional oil and gas companies are under pressure to improve their environmental and social governance to tackle issues such as global warming. This has made it more difficult for developing oil and gas countries to access capital. Funders and shareholders are applying more stringent measures and conditions, triggering a shift towards relatively less carbon-intensive operations—such as gas—and more socially and environmentally friendly operations. This shift puts pressure on available capital for investment by IOCs, and therefore on revenues to these companies and host states. This has led to a downward trend in the value of IOCs.

Climate change and the ongoing global drive to reduce carbon emissions has had a major impact on long-term investment in the hydrocarbon production business. To adapt to the global demand for low-carbon energy, oil majors are reviewing their business models, which is impacting the execution of new upstream contracts, including PSCs. The Paris Agreement seeks to strengthen the global response to the threat of climate change and holds the increase in the global average temperature to well below 2°C, above pre-industrial levels. The Agreement pursues efforts to limit the temperature increase to 1.5°C, above pre-industrial levels, recognizing that this would significantly reduce the risks and impacts of climate change. Furthermore, the Agreement requires that finance flow consistently with a pathway towards low greenhouse gas emissions and climate-resilient development.[30] The requirement to redirect finance flow into low greenhouse emissions has compelled major banks and equity investors to reconsider its carbon emission contributions regarding hydrocarbon businesses in traditional hydrocarbon production ventures. Therefore, these ventures are attracting less investment as opposed to low carbon business models.

Further, in the aftermath of the COVID-19 pandemic, countries that are heavily dependent on oil and gas are taking more measures to ensure the continued operations of oil companies to protect the industry. States which are otherwise not known to have a business environment that facilitates pro-business policies are acting quicker than they have in the past. Currently, states are approving annual work programs and budgets by means of video conference and/or correspondence. A possible advantage to this trend is that these more efficient means of operation become embedded and standard practices for states and the industry.

The Covid-19 pandemic, coupled with the global demand for low-carbon energy, is further shaping the remodeling of integrated and independent oil companies. Net zero goals imply huge shifts in strategy for global oil majors, but approaches vary.[31] He notes further that 2020 may be remembered as a tipping point for the oil and gas industry. During a global pandemic and economic lockdown which were expected to wipe out over 8 million billion dollars of oil demand, producers slashed capital spending to the lowest in 15 years. The world's most prominent oil producers have announced major cuts to capital spend, as well as asset write downs and dividend cuts; industry leaders such as BP, Total, Shell, and others have made headlines by effectively redoubling their commitment to long-term net-zero targets. As of 2020, nearly every single international major made some form of a low-carbon commitment. The more ambitious of these aspire to be "net zero" by 2050, but all companies have some form of commitment to reducing the greenhouse gas intensity of existing operations and to expand activity related to low-carbon energy carriers such as renewable power, biofuels, and

30. Conference of the Parties, Adoption of the Paris Agreement, Dec. 12, 2015.

31. Mark Mozur, *The path to net zero: oil majors' transition strategies and capital spending*, S&P Global: Commodity Insights (Sep. 22, 2020, 3:34 PM), https://www.spglobal.com/commodityinsights/en/market-insights/blogs/oil/092220-the-path-to-net-zero-oil-majors-transition-strategies-and-capital-spending.

hydrogen. Furthermore, the reduced, long-term oil demand outlook has caused many producers to adopt lower pricing guidance.[32]

Platts Analytics, in its prediction model in 2020, assumed that supply growth is expected to be optimized across cost, meaning that incremental oil production is almost exclusively restricted to core OPEC producers.[33] Overall, from 2025 to 2050, this key assumption implies $3.4 trillion in total upstream capex, versus $9.5 trillion in the reference case, effectively leading to $6.1 trillion in potential long-term capital reallocation.[34]

Cost recovery correlates with oil price. The fast-paced increase in the price of crude oil in the early part of 2022 was a result of the February 2022 Russia-Ukraine war. According to the International Energy Agency ("IEA"), Russia is the world's third-largest oil producer behind the United States and Saudi Arabia. In January 2022, Russia's total oil production was 11.3 mb/d, of which 10 mb/d was crude oil, 960 kb/d condensates, and 340 kb/d NGLs. By comparison, U.S. total oil production was 17.6 mb/d, while Saudi Arabia produced 12 mb/d. Russia is also the world's largest exporter of oil to global markets and the second-largest crude oil exporter behind Saudi Arabia. In December 2021, it exported 7.8 mb/d, of which crude oil and condensate accounted for 5 mb/d, or 64%. The Russia-Ukraine war has not yet resulted in a loss of oil supply to the market. Prices nevertheless surged following the news, on expectations that sanctions against Russia would cripple energy exports. It is currently unclear what the impact of sanctions will be on energy flows and how long any potential supply losses will last.[35]

Current high oil prices are favorable for cost recovery and help to accelerate oil and gas project paybacks. While the war has introduced unexpected new dynamics into the energy shift to low-carbon options, the long-term drive to net-zero carbon remains effective.[36]

---

32. *Id.*
33. *Id.*
34. *Id.*
35. *Oil Market and Russian Supply*, IEA (last accessed May 9, 2023) https://www.iea.org/reports/russian-supplies-to-global-energy-markets/oil-market-and-russian-supply-2.
36. *Id.*

3. Case Studies

3.1. Angola

a) The evolution of PSCs and cost recovery in Angola

Pursuant to the Law No. 10/2004 ('Petroleum Activities Law')[37], as amended by the Law No. 5/2019,[38] the Angolan oil and natural gas reserves are owned by the State. The exploration and production activities may only be performed either under a proper prospecting license issued by the Ministry of Natural Resources and Petroleum and Natural Gas or a concession granted by the Government. Law No. 5/2019 changed the Petroleum Activities Law by establishing that the recently created National Oil, Natural Gas and Biofuels Agency ('ANPG') as the national concessionaire and holder of mining rights.[39] ANPG was created by Presidential Decree No. 49/2019 in the context of the restructuring of the Angolan oil and gas sector and replaced Sonangol, the Angolan national oil company, as the national concessionaire, excluding Sonangol's regulatory and operational roles.[40] ANPG has the specific task of regulating, inspecting, and promoting the performance of the oil and gas activities in Angola.

Pursuant to the Presidential Decree No. 52/2019, concessions may be awarded in three (3) different systems, as follows:

(i) Public tender: which follows the Angolan general rules for competitive bids as provided in the Presidential Decree No. 86/2018, and the concession is awarded by means of a specific concession decree. Sonangol may have a stake of at least 20% in the asset and will have the right to be financially carried up, by international partners, to a maximum of 20% of the research or exploration operations expenditures. Under this system, the following contracts will be executed: (a) commercial contract, (b) consortia (incorporated joint venture) contract, and (c) production sharing agreement;

(ii) Limited public tender: reasons of national strategy interests may justify the possibility of a tender process to a limited number of

37. Petroleum Activities Law, No. 10/04 (Angl.), https://faolex.fao.org/docs/pdf/ang81903E.pdf (last accessed May 9, 2023).

38. Law No. 5/2019 (Angl.), https://faolex.fao.org/docs/pdf/ang185279.pdf (last accessed May 9, 2023).

39. *Id.*

40. Presidential Decree No. 49/19 (Angl.), https://faolex.fao.org/docs/pdf/ang184689.pdf (last accessed May 9, 2023).

previously selected companies. It is recommended that such a system is used in the case of areas already abandoned or relinquished. The selected company must meet technical and technological requirements. The minimum work obligations will be in line with the state's strategy for the development of the oil and gas industry. The general rules for competitive bids as provided in Presidential Decree No. 86/2018 will be applied; and

(iii) Direct award: the national concessionaire will be directly hired through a concession decree, and in its turn, such national concessionaire will execute a risk service agreement with an oil and gas company or a joint venture. Such companies must meet technical and technological criteria, as well as have experience in similar basins.[41]

Under the production sharing contracts executed in Angola, all costs, expenditures, and risks, including geological risks, associated with the oil and gas operations are taken by the contractor group. The Contractor group is responsible for paying all costs and expenditures and has the right, up to a certain limit, to recover as cost oil its expenditures and costs (up to 55% in the case of ultra-deep waters blocks and 50% in deep waters blocks). The costs that are not recovered in a certain accounting period are carried over to the following periods, provided that such recovery does not go beyond the contractual term. The production sharing contract details the costs that may be recovered in accordance with their categories (exploration, development, and production costs). The production-sharing contract has two phases: exploration and production. The exploration phase may have two (2) exploratory periods, including a mandatory initial exploration period and an optional subsequent exploration period. The term of each phase and period is negotiated and established in the relevant production-sharing contract. Each exploration period has a minimum work program. In case the activities provided in such a minimum work program are not fulfilled in a timely manner, the contractor group will be subject to penalties. A work program and budget for the exploration, development, and production phases must be annually prepared by the operator, approved by the operating committee, and then submitted to the relevant governmental authority. The Operator will conduct daily operations in line with the approved work program and budget,

41. Decree Approving the General Strategy for the Allocation of Oil Concessions for the Period 2019-2025, No. 52/2019 (Angl.), https://faolex.fao.org/docs/pdf/ang184723.pdf (last accessed May 9, 2023).

and the operating committee will supervise the operator and coordinate the joint operations. Half of the members of the operating committee will be appointed by the Government and will be chaired by a representative of the Government.

In case oil or natural gas is discovered in a drilled well and the contractor group understands that such discovery can produce oil and natural gas, the contractor group shall notify the governmental authorities that it is a commercial well. Then, the contractor group will have a certain period of time to test and appraise the discovery and decide whether it is a commercial discovery. If the contractor group decides that it is a commercial discovery, the governmental authorities must be notified and then the contractor group must prepare a proper development plan, which must subsequently be approved by the relevant governmental authority.

The production phase will last between twenty (20) to twenty-five (25) years—varying in each contract—beginning from the notification to the government of the commercial discovery. The production phase may be extended, and if so, Sonangol will have a preemptive right to operate and acquire up to 20% of the participating interest in said project. If a development operation has not commenced in a timely manner, ANPG has the right to request the contractor group execute exclusive risk operations. The contractor group may recover its costs and expenses up to a maximum portion of all oil and natural gas produced in the relevant development area. Costs not recovered in a certain year may be carried forward to following years.

Oil and natural gas produced, other than those used in operations or related to cost oil to be recovered by the contractor group, is shared between the national concessionaire and the contractor group as profit oil. The share of each party in the profit oil is calculated quarterly in accordance with the nominal rate of return (ROR) of the contractor group in the preceding quarter after taxes. The greater the contractor group's ROR, the less the share of the profit oil allocated to the contractor group.

Each party has the right to lift and dispose of its share of the profit oil. However, the national concessionaire, as well as the Government, have the right to buy, and the contractor group has the obligation to sell, a certain percentage of the contractor group's share of the profit oil.

The transfer of participating interests must have prior approval of the Ministry of Natural Resources, Petroleum and Natural Gas. The assignee must have recognized capacity, technical knowledge, and financial capability. In case of assignments to affiliates other than the assignor, Sonangol will have a preemptive right.

b) Challenges and concerns with PSCs and cost recovery in Angola

The political risks, conflicts of interest involving top governmental authorities, lack of foreign currency liquidity, concentration of the Angolan economy in Sonangol's subsidiaries in different industries, Sonangol's deep indebtedness, and the plunge of oil prices in the last decade—especially because most of the exploration and production activities in Angola are conducted in ultra-deep waters (i.e. the pre-salt layer) and thus are capital-intensive—have severely impacted the Angolan upstream industry in the past.[42]

In order to attract international investments in a competitive and challenging environment due to the dip of oil prices, guaranteeing political stability, predictability, and legal certainty in the business environment are key for attracting new players and encouraging investments from IOCs that are already operating in Angola.

Since the election of Angola's current president, Mr. João Manuel Gonçalves Lourenço, replacing Mr. Eduardo dos Santos in September 2017, the Angolan oil and natural gas legal and regulatory framework has been deeply reshaped, aiming to expand the knowledge of the Angolan reserves, increase the competition, promote direct foreign investments, and bolster natural gas exploration and production.

c) Solutions adopted or considered to solve these challenges and concerns.

As part of measures to improve the Angolan economy, the Angolan Government announced a privatization program affecting approximately 195 companies, with an intention to sell the Government's whole or partial shares in the state-owned oil and gas companies Sonangol and China Sonangol International.[43]

Presidential Decree No. 86/18 approved a plan aimed at reviewing Angolan oil's legal and regulatory framework in order to strengthen hydrocarbon production.[44] Following the Presidential Decree, several key

42. Lucy Corkin, *After the Boom: Angola´s Recurring Oil Challenges in a New Context*, THE OXFORD INSTITUTE FOR ENERGY STUDIES (May 2017), https://a9w7k6q9.stackpathcdn.com/wpcms/wp-content/uploads/2017/05/After-the-Boom-Angolas-Recurring-Oil-Challenges-in-a-New-Contect-WPM-72.pdf (last accessed May 9, 2023).

43. *See Investment Climate Statements, Angola*, U.S. DEP'T OF STATE https://www.state.gov/report/custom/b7e3e02094-2/ (last visited May 9, 2023).

44. *Angola - Country Commercial Guide*, INT'L TRADE ADMIN., https://www.trade.gov/country-commercial-guides/angola-oil-and-gas (Aug. 5, 2022) (discussing New Regulations on Local Content in the Oil Sector, Presidential Decree No. 86/18).

pieces of legislation were passed, including: (i) Presidential Decree No. 282/2020, which approved hydrocarbon exploration and production strategies for Angola from 2020 to 2025;[45] (ii) the Presidential Decree No. 271/2020, which set forth a local legal regime applicable to the oil and gas industry;[46] (iii) Presidential Decree No. 49/2019, which created the National Agency of Petroleum, Natural Gas and Biofuels ('ANPG');[47] (iv) Law No. 5/2019, which changed certain provisions of the Petroleum Activities Law; (v) Presidential Decree No. 91/2018, which established rules and procedures for the abandonment of wells and the decommissioning of oil and gas facilities;[48] (vi) Presidential Legislative Decree No. 5/2018, which established the legal regime for additional research activities;[49] (vii) Presidential Decree No. 6/2018, which defined the incentives and procedures for adjusting contractual and fiscal terms applicable to marginal areas;[50] and (viii) Presidential Legislative Decree No. 7/2018, which established the legal and fiscal regime applicable to upstream activities.[51]

Among such changes in the legal framework to exploration and production activities, it is notable that Presidential Decree No. 52/2019 established that ANPG must periodically conduct comparative studies of other countries' oil and gas sectors in order to assess the attractiveness of the Angolan oil and gas industry, considering the growth of worldwide competition for financial resources to be invested in oil and gas projects.[52] This is an important provision for the continued development of the Angolan oil and natural gas industry. In addition, the Presidential Decree noted above set forth that competitive bid rounds must be held for the granting of E&P rights. The decree also aims at promoting the conduct of studies, including the acquisition, and reprocessing of geological and geophysical data, including

---

45. Presidential Decree Approving the Hydrocarbon Exploration Strategy from 2020 to 2025, No. 282/20 (Angl.). https://www.fao.org/faolex/results/details/en/c/LEX-FAOC198633/ (last accessed May 9, 2023).

46. Presidential Decree New Regulations on Local Content in the Oil Sector, No. 271/20 (Angl.).

47. Presidential Decree Creating the National Agency for Oil, Gas, and Biofuel, No. 49/19 (Angl.). https://www.fao.org/faolex/results/details/en/c/LEX-FAOC184689/ (last accessed May 9, 2023).

48. Presidential Decree No. 91/2018 (Angl.).

49. Presidential Decree No. 5/2018 (Angl.).

50. Presidential Decree No. 6/2018 (Angl.).

51. Presidential Decree No. 7/2018 (Angl.).

52. *See* Presidential Decree Approving the General Strategy for the Allocation of Oil Concessions for the Period 2019-2025, No. 52/2019 (Angl.). https://www.fao.org/faolex/results/details/en/c/LEX-FAOC184723/ (last accessed May 9, 2023).

(i) new frontier areas, such as the areas of the Etosha, Okavango and Casange inland basis, and of the Namibe offshore and onshore basin, (ii) areas near to the producing areas of the Congo basin, and (iii) reassessments of the relinquished pre-salt areas from the 2012 campaign.

With regards to cost recovery, it should be noted that, in order to deal with these challenges, there is an uplift factor in Angola, which is a mechanism whereby investors may receive an additional percentage of recovered costs corresponding with the development of a certain are, as compensation for the delay in the total recovery of the costs, when such recovery does not occur within the first five years of the contract. Since most of the expenditures occur before the first year of production, this allows the contractor group to accelerate investments. As a result, there is a reduction in the amount to be taxed due to the increase of cost oil and, consequently, the reduction of profit oil.

3.2. Brazil

a) The evolution of PSCs and cost recovery in Brazil

The Brazilian Federal Constitution of 1988, which is still in full force and effect, established the State monopoly over upstream activities.[53] Such monopoly was exercised by Petrobras, a mixed capital company controlled by the Brazilian State, until constitutional amendment No. 9 (from 1995), which loosened the monopoly by allowing the Brazilian Federal Government to contract with private parties.[54] This was further regulated by Federal Law No. 9,478/1997 ("Petroleum Law"), which created the current oil and gas regulator, the National Agency of Petroleum, Natural Gas and Biofuels (ANP), and set forth the concession contracts regime which applies to all areas other than those granted under Federal Law No. 12,351/2010 ("Pre-Salt Law") and Federal Law No. 12,276/2010 ("Transfer of Rights Law").[55]

---

53. BRAZ. FEDERAL CONSTITUTION, art. 177 (Braz.).

54. *Id.* ¶ 1.

55. Transfer of Rights Law authorized the Federal Government to onerously assign to Petrobras the right to explore and produce up to 5 billion barrels of oil equivalent in a prolific area of the pre-salt polygon in exchange of the acquisition, by Petrobras, of government debt securities, in the total amount of 74.8 billion Brazilian Reais. As a result, the Brazilian State's share in Petrobras' stock capital was increased through the issuance of public debt bonds. The transfer of rights agreement had a revision mechanism on the declaration of commerciality of the relevant fields. Over the last few years, it was discovered that such transfer of rights agreement areas held far more than 5 billion barrels of oil equivalent (which includes natural gas). Petrobras was reimbursed by the Federal Government in USD 9.058 billion and the relevant surplus volumes were offered in a bid round in 2019 under the production sharing contract regime.

Following discoveries of ultra-deep waters offshore fields, the Pre-Salt Law was enacted in 2010, aimed at increasing the State's control over Brazilian reserves. The current Brazilian upstream legal framework is composed of Petroleum Law, Pre-Salt Law, and Transfer of Rights Law.

The Pre-Salt Law establishes the production sharing contract regime for all pre-salt polygon areas and other areas deemed strategic by the National Council of Energy Policy (CNPE).[56] The geographic coordinates of the pre-salt polygon are defined in an exhibit within the Pre-Salt Law. Production-sharing contracts may be awarded in competitive bids. The criteria are composed of a fixed signing bonus and the highest proposal for the share of profit oil payable to the Federal Government, or directly contracted with Petrobras.[57] Although the Pre-Salt Law was enacted in 2010, it was only by the end of 2013 that the first bid round under the production-sharing contract for the pre-salt area of Libra took place. Notably, no blocks have been directly contracted with Petrobras to date. Initially, Petrobras was the mandatory operator of all the areas granted under the Pre-Salt Law, with at least a 30% participating interest. Such mandatory operatorship took the form of a preferential right to operate in said areas with a minimum working interest of 30% by means of the changes made in the original wording of the Pre-Salt Law by the Federal Law No. 13,365/2016, and as further regulated by Federal Decree No. 9,041/2017. Petrobras must express its interest in operating the relevant areas to be bid within thirty (30) days, beginning from the issuance of the CNPE's resolution. This will provide the technical and financial parameters of the blocks to be bid for. Then, based on the express interest from Petrobras, CNPE will propose to the President of Brazil the blocks and minimum participating interests it recommends Petrobras operate.[58] If Petrobras has exercised its preferential right but it is not part of the winning consortia of bidders, and the share of the profit oil offered to the Federal Government is higher than the minimum percentage established in the tender protocol of the relevant bid round, Petrobras will have the option to join in said proposal.

In order to manage the Federal Government's interests under production-sharing contracts, commercialize the Federal Government's share of the profit oil, and represent the Federal Government in unitizations where the reservoir straddles contracted areas into open acreages located in the pre-salt

56. Exploitation and Production of Oil, Natural Gas, and Other Liquid Hydrocarbons, and Amending the National Energy Policy, Law No. 12,351, art. 1 (Braz.). https://www.fao.org/faolex/results/details/en/c/LEX-FAOC121303/ (last accessed May 9, 2023).

57. *Id.* at art. 8 (Braz).

58. *Id.* at art. 4 (Braz).

polygon or in strategic areas, Pré-Sal Petróleo S. A. (PPSA) was created. PPSA is a company wholly owned by the Federal Government.

Under the Brazilian production-sharing contracts, the contractor(s) must fulfill the minimum exploratory obligations during the exploration phase, and in case of a discovery, the Operator must notify ANP and submit a proper appraisal plan, which will be analyzed and approved by the ANP. If, after such appraisal, the contractor(s) understand(s) that such discovery is commercial, the contractor(s) must submit to the ANP a notification of declaration of commerciality and a proposed development plan within one hundred and eighty (180) days. Contractor(s) must also submit a yearly work program and budget for the relevant phase and a production plan during the production phase.

Under the Brazilian concession contracts, the concessionaire is entitled to all oil and gas produced and shall pay government takes and taxes to governmental authorities. Differently, pursuant to the Brazilian production sharing contracts, contractor(s) conduct(s) the exploration, appraisal, development, production, and decommissioning operations; in cases of commercial discovery, contractor(s) will be entitled to recover cost oil, a certain production volume corresponding to the royalties, as well as a portion of the profit oil that will be shared between the contractor(s) and the Federal Government. Such recovered costs may be related to: (i) acquisition of inputs; (ii) charter or rental of equipment; (iii) acquisition, processing, and interpretation of geological, geophysical, and geochemical data; (iv) goods included in fixed assets; (v) maintenance, repair, and conservation of equipment; (vi) repair of lost or damaged equipment in daily operations; (vii) acquisition and maintenance of insurances approved by the operating committee; (viii) operations in vessels and aircraft; (ix) inspection, storage, offload, and transportation of equipment and materials; (x) obtainment of permits and easements; (xi) training related to performed activities; and (xii) personnel directly engaged in operations. The production-sharing contract also establishes percentages for the recovery of costs that are not directly related to the operations or that are not easily identified.

Only the costs and expenditures previously approved by the operating committee of the production-sharing contract and by the PPSA itself are recoverable. PPSA appoints half of the members of the operating committee and its president, who will have a qualified vote and veto power in certain matters. Contractor(s) may recover costs and expenditures incurred before the signing date of the relevant production sharing contract and up to the creation of the operational committee, provided that such costs and expenditures are concurrently: (i) related to the acquisition of data and information, obtainment of governmental licenses, authorizations and permits; (ii) possible to be recovered under the terms and conditions of the production-sharing contract; and (iii) ratified by the operating committee before its recovery as cost oil. During the production phase, the contractor(s) may receive its entitlement to production related to cost oil limited to a certain percentage of production, as contractually provided per the number of years of production. The costs, as duly adjusted, that exceed such limits may be carried forward in the following years. If, by the end of the term of the production-sharing contract, there is still a balance of non-recovered costs and expenditures as cost oil, the contractor(s) will not have any further rights to cost recovery.

Besides the profit oil allocated to the Federal Government, the contractor(s) is/are also subject to royalties and taxes. Contractors must comply with local content commitments and one percent (1%) of the production gross revenues must be invested in research, development, and innovation in case the production thresholds established in the relevant production-sharing contract are reached.

Transfer of participating interests is possible and subject to prior approval from the Ministry of Mines and Energy, with the consultation from the ANP. Assignees must be technically, financially, and legally qualified, pursuant to ANP requirements. Petrobras may neither transfer its minimum thirty percent (30%) working interest, nor the operatorship it obtains when it exercises its preemptive right to operate. The production-sharing contract has a term of thirty-five (35) years, which may not be extended.

b) Challenges and concerns with PSCs and cost recovery in Brazil

The Brazilian production-sharing contract regime is usually less financially attractive than the Brazilian concession contract regime for several reasons. The internal rate of return (IRR) of projects developed under the production-sharing contract model in Brazil is usually below the IRR for fields under the concession contract model, while the government take (including a royalties rate of fifteen percent (15%) compared to a maximum royalties rate of ten percent (10%) in the concession contract regime) and the break-even of such projects developed under the production-sharing contract model are higher than the ones conducted under the concession contract system.[59] Another challenge is that the Pre-Salt Law defined the areas to be

59. Cooperação e Pesquisa IBP – UFRJ, *Comparação dos Modelos Fiscais de Partilha e Concessão*, Proposta Comercial (Novembro 2016), https://www.ibp.org.br/personalizado/

subject to the production-sharing contract through the geographic coordinates of all pre-salt polygon areas, including areas with high exploratory risks that are less attractive to the upstream companies. Such areas should be bid on in the concession contract regime in order to increase their attractiveness.

The attractiveness of the bid rounds is another point of concern, especially considering that only one (the area of Aram) out of five areas (Aram, Bumerangue, Cruzeiro do Sul, Sudoeste de Sagitário and Norte de Brava) awarded in the last bid round was held under the production-sharing contract regime for pre-salt areas (Pre-Salt Round 6). There was only one bidder, and the winning bidder, consortia, formed by Petrobras and the Chinese CNODC, offered the minimum share of profit oil to the Federal Government, as defined in the relevant tender protocol. The requirement of huge up-front payments (e.g., signing bonuses) is one of the key issues negatively affecting the attractiveness of certain bid rounds under the production-sharing contract regime in Brazil. Another issue is that, although Petrobras is no longer the mandatory operator of these areas, Petrobras still has a preferential right to operate, as explained above, which grants the company the possibility to participate in the winning joint ventures in the bid round, even if it is contrary to the best interests of other companies that formed the winning consortium in the relevant bid round.

The governance of the joint venture is also challenging to production-sharing contracts executed in Brazil since there is a greater degree of control by the State in comparison to the concession contract regime. Although PPSA has no participating interest in the joint venture, it has the right to appoint half of the members of the operating committee, including its chairman, who will have a qualified vote or even veto power in certain matters. PPSA is also in charge of the approval of recovery of costs and expenditures as cost oil. Since the obligations under production-sharing contracts are more complex than in the concession contracts, costs related to compliance with the obligations under the production-sharing contracts in Brazil are also higher than in concession contracts. For instance, resources are needed to prepare and control all the documentation in connection with recoverable costs and cost oil.

As for cost recovery, upstream companies operating in Brazil and trade unions have been expressing concerns over the past bid rounds on: (i) the cost recovery approval process; (ii) the financial adjustments on the costs to

uploads/2017/01/IBP_UFRJ_TD-Compara%C3%A7%C3%A3o-Partilha-e-Concess%C3%A3o_04_11.pdf.

be recovered; (iii) the possibility of recovering all costs before the termination of the relevant contract; (iv) caps on the percentage of production that may be recovered as cost oil; (v) the possibility of recovering research, development, and innovation expenditures; (vi) the need to increase the contractual amounts of expenditures that are not directly related to the operations and could be recovered as cost oil; and (vii) the possibility of recovering lifting costs. In line with the best regulatory practices, before the publication of the final versions of the tender protocol and production-sharing contract of each relevant bid round, ANP publishes draft versions of such documents on its website and gives relevant stakeholders a certain period of time to submit suggestions for improvements within a public consultation process. This public consultation process is followed by a public hearing. Below are the main points that operators in Brazil have been raising over past bid rounds.

According to clause 5.2 of the production-sharing contract of the so-called Pre-Salt Bid Round 6, the following conditions should be observed for cost recovery: (i) costs should be previously approved by the Operating Committee (except if approval is not required by the relevant contract); and (ii) the costs should be previously recognized by the managing party (PPSA). During the public consultation process of Pre-Salt Round 6, the Brazilian Institute of Petroleum, Natural and Biofuels ("IBP"), a trade union that represents most of the upstream companies operating in Brazil, suggested that the cost recovery should be approved by the time of the ballot approval within the Operating Committee; thus, it would not require the subsequent recognition phase by PPSA.[60] Accordingly, ExxonMobil suggested that PPSA should recognize the recovery of expenditures that are in line with the approved Work Program and Budget, by arguing that said provision would follow best international practices and would give a higher degree of clarity and certainty to the cost recovery process.[61]

As provided in clause 5.4.2 of said production-sharing contract model, the expenditures considered as cost oil should be annually adjusted, preferably by the IPCA index rate (the national consumer price index rate), which reflects the Brazilian inflation rate, or by other index rates that reflect the oil and gas industry costs as chosen by PPSA. During the relevant public consultation process, ExxonMobil suggested that other index rates should be

60. Gov.br, *Consulta e Audiencia Publica* (Oct. 14, 2021), https://www.gov.br/anp/pt-br/rodadas-anp/rodadas-concluidas/partilha-de-producao/6a-rodada-partilha-producao-pre-sal/consulta-e-audiencia-publica.

61. *Id.*

mutually agreed by the Parties (not exclusively by PPSA).[62] IBP has already expressed that, as IPCA is an index rate related to the prices of consumer goods, it is not the most appropriate index rate for the oil and gas industry. In addition, Shell suggested that such an adjustment should be expanded from the date when the expenditures actually occurred (not annually).[63]

Expenditures related to research, development and innovation projects cannot currently be recovered as cost oil. Shell and IBP suggested the possibility of recovering such expenditures if they were applied for the specific and exclusive benefit of the field, subject to the relevant production sharing contract, as the expenditures related to development and improvement of the activities that are within the scope of the contract should be considered for recovery as cost oil.[64] More broadly, Petrobras and IBP suggested the possibility of recovering as cost oil the investment in research, development, and innovation projects in Brazilian universities.[65]

Furthermore, Shell and IBPr suggested an increase in the amounts and percentages of the expenditures that are not directly related to the operations, but could be recovered as cost oil, considering that, based on the experience of the companies operating in the Brazilian pre-salt polygon, the amounts currently provided in the relevant production-sharing contracts are very low. It was suggested that, in the case of expenditures reaching an amount greater than 5 million Brazilian Reais, which were not directly related to the operations and were not easily identified in the Exploration Phase, such expenditures could be recovered as cost oil up to 2% of the monthly total expenditures recognized as cost oil. Previously, the 2% cap was only applicable to expenditures between 5 and 15 million Brazilian Reais. Above this amount, a 1% rate was applicable.[66] Shell and IBP also suggested the division of the Production Phase rate (1%) into a Development Phase rate (2.5%), and an After Development Phase rate (2%), regardless of the amount of the relevant expenditures.[67]

IBP also suggested that the costs for lifting hydrocarbon production and its maritime transportation to ship-to-ship points in Brazilian waters, where such production should be delivered to other vessels that would export said oil, should be recovered as cost oil. None of the above-mentioned suggestions were accepted by the ANP.

---

62. *Id.*
63. *Id.*
64. *Id.*
65. *Id.*
66. *Id.*
67. *Id.*

It may be argued that the production-sharing regime in Brazil is, from an economic standpoint, very disadvantageous, because it gives the wrong stimulus to companies that, inflate costs to be recovered as cost oil to reduce the taxation on profit instead of maximizing efficiency. This is because, by increasing the amount that will be recovered as cost oil, profit oil to be shared between the contractor group and the Federal Government will be reduced and, consequently, the taxation by the Corporate Income Tax (IRPJ) and the Social Contribution on the Net Profit (CSLL) will also be reduced. This is because the calculation basis of these taxes, generally, will be the contractors' share of the profit oil.

c) Solutions adopted or considered to solve these challenges and concerns.

During the relevant public consultation and public hearing processes of each bid round, the upstream companies and trade unions usually submit suggestions for improvements to the Brazilian cost recovery system. Although there is still a long path to reach the best cost recovery practices from both economic and operational standpoints, it could be said that there were already positive developments in the Brazilian cost recovery system, especially in regard to the cap on the maximum monthly production that could be used for purposes of cost recovery. Under the First Pre-Salt Round, only 50% of the monthly production could be recovered as cost oil within the first 2 years, and 30% of the monthly production in the following years. Due to the pressure of the oil companies and trade unions, the maximum percentage of cost recovery was increased to 80% of the production in the most recent production-sharing contracts.

In addition, it could be said that there is a consensus between the players of the Brazilian oil and gas industry and the Federal Government that improvements in the Pre-Salt Law are necessary and urgent to unlock investments.

The Bill of Law No. 3,178/2019, authored by Senator José Serra, changes the Pre-Salt Law, providing that the pre-salt and strategic areas will be preferably contracted under the production-sharing contract regime, but the concession contract regime may be applied to such areas when the regime is deemed more beneficial to the country, considering the geological potential of areas to be bid does not socially and financially justify their bidding under the production-sharing contract. CNPE, with consultation from the ANP, will define the best E&P legal regime to be adopted in the bid round of such pre-salt and strategic area, considering the geological data and information provided by the ANP and the best social and financial return to society.

Although such social and financial criteria may be considered vague, and CNPE, which is a government body, will have a great degree of discretion to define such criteria, the possibility of granting pre-salt polygon areas through the concession regime could be considered progress. In addition, the referenced Bill of Law terminates with Petrobras' preferential right to operate with a minimum participating interest of 30% by establishing that all bidders must be equally treated in the bid rounds under the production-sharing contract regime. This Bill of Law is part of a list of priorities from the Brazilian Ministry of Economy in an effort to deliver recovery of the Brazilian economy amid the COVID-19 outbreak.

There is also the Bill of Law No. 5,007/2020, authored by the federal representative Paulo Ganime, that goes beyond the Bill of Law No. 3,178/2019 by proposing that all pre-salt and strategic areas will be contracted under the concession contract regime. As mutually agreed, upon by the Federal Government and the contractor(s), the possibility of migrating executed production-sharing contracts to the concession contract scheme will be offered. Similar to Bill of Law No. 3,178/2019, any competitive advantage or preemptive right in the bid rounds for the granting of E&P rights is prohibited. Petrobras will also be allowed to transfer its operatorship and minimum participating interest when it has exercised its preferential right before the enactment of the law resulting from the Bill of Law No. 5,007/2020. In regard to governance, the referenced Bill of Law provides that PPSA will appoint representatives to the operating committee, corresponding to the percentage of the Federal Government's share of the profit oil. As an alternative for the commercialization of the Federal Government's share of the profit oil, the Bill of Law allows the Federal Government to authorize the payment by the contractor(s) in cash instead of the allocation in-kind.

3.3. Indonesia

a) The evolution of PSCs and cost recovery in Indonesia

In 1965, Indonesia issued its first-generation PSC for the first time. This regulation ended the concession system in Indonesia, which had been present since the first oil discovery in Sumatra in 1885. The PSC was introduced to increase investment attractiveness in the oil and gas business and maximize Indonesia's natural resources potential. According to the Republic of Indonesia's constitution of 1945, "The land, the waters and natural resources within shall be under the power of the State and shall be used for the greatest benefit of the people."[68] This means Indonesia tried to realize what was written in the Republic of Indonesia's constitution in 1945.

There have been seven generations of PSC in Indonesia, and each generation has a different percentage due to the adjustment percentage or elements change therein. The key elements in the Indonesian PSC are as follows: (1) First Tranche Petroleum, (2) Cost Recovery Limit, (3) Income Tax Equity Split after tax, (4) Investment Credit, (5) Domestic Market Obligation, (6) Depreciation, (7) Interest Recovery, and (8) Abandonment Liability.

The percentage adjustment and additional element changes were replaced based on the need for government and contractor parties; these changes balanced the benefits to the parties to maintain an attractive PSC.

The first tranche petroleum (FTP) was created and used to guarantee a portion of the income to the State to be obtained before deduction. However, since the fifth generation of PSC in Indonesia, FTP's are not to be shared with contractors anymore.

The second element is the cost recovery limit. Cost recovery is taken from gross revenue and awarded to Contractors by SKK Migas—Implementing Special Task Force Upstream Oil and gas business activities—as the government representative in PSC Cost Recovery. The costs that can be recovered after the allocation of FTP are subject to a percentage limitation. However, the newest PSC system in Indonesia, which is the seventh generation, does not include any cost recovery limit percentage.

Besides profit oil or gas allocated to the government, the contractor needs to implement one of the elements in PSC Indonesia, the Domestic Market Obligation (DMO). In this DMO regulation, the contractor must give a portion of its oil and gas production to the Indonesian government, the actual proportions and discount rates varying depending on the PSC generation.

There are also regulations regarding the type of depreciation used and the depreciation year scale. The common depreciation type used in PSC Indonesia is the decline balance method. Based on the increasing awareness of the commercial environment with each passing year, PSC Indonesia has added new elements since the fourth Generation of PSC in Indonesia, whereby the contractor must provide for abandonment activities in its project to ensure that the wells are safe after abandonment.

Another element is investment credit. Investment credit is cost-recoverable for capital expenditure on product facilities subject to tax. This

---

68. CONST. OF THE REPUBLIC OF INDON. art. 33.

investment credit is applied after the FTP has been distributed, but before the deduction of operating costs. However, investment credit is not entirely helpful to the contractor, and everything depends on existing conditions. This is because the investment credit is taxable.

The contract agreement between the contractor and the government has a term of thirty (30) years with a possible extension. It consists of ten (10) years for exploration activity and twenty (20) years of production activity.

b) Challenges and concerns with PSCs and cost recovery in Indonesia

The Indonesian PSC is not as attractive as other PSC systems, especially in comparison to other Southeast Asian countries. Some of the biggest issues of the Indonesian PSC are its cost recovery system, which is considered less transparent, and the miscommunication between government parties responsible for cost recovery.

The biggest challenge in the Indonesian PSC is gold-plating. Gold-plating is a well-known term for the practice of running a project to make changes and incur costs outside the project's scope and increase unnecessary investment. However, the government already tried to settle this cost recovery problem by assigning SKK Migas to control all of Indonesia's oil and gas activities. The government's most recent strategy involves implementing the seventh generation of Indonesian PSC, which eliminates the cost recovery elements.

A marginal field is a field that has limited profit margins and is unattractive for various reasons. Marginal fields need a lot of support so that they can still produce. Usually, the host country provides several incentives and relaxed regulations to assist the contractor. The Indonesian government does not want to offer a higher share to the contractor, and the incentives are not sufficiently attractive to develop marginal fields. Therefore, developing marginal fields in Indonesia using the PSC system is considered unattractive from an investor's perspective.

Another challenge is the convoluted bureaucracy in Indonesia. The PSC cost recovery system in Indonesia has a lot of interference from the authority, which can hamper the contractor. This can reduce investors' interest in exploration and production in Indonesia, considering the possibility of unforeseen obstacles that could increase unrecoverable costs.

c) Solutions adopted or considered to solve these challenges and concerns.

In 2017, the Vice Minister of Energy and Mineral Resources of Indonesia, Arcandra Tahar, introduced the new PSC system in Indonesia, PSC Gross

Split.[69] The PSC Gross Split system seeks to improve the system existing in the previous PSC to improve fairness to the government and contractors. The PSC Gross Split system will prevent interference by the contractor in the debate in determining the components to gain more profit, which was typical of the previous PSC system. The variable and progressive split in PSC Gross Split provides flexibility to the contractor, whether they want to gain further profit. With the split percentage, the contractor can extract benefit through the specific variables that are available to it.

The PSC Gross split can be defined as a system that can share the pain and the gain. Another advantage of additional split besides the base split is to prevent an imbalance of profit-sharing and avoid the risk of split incentives.

According to the regulation of the Minister of Energy and Mineral Resources of Indonesia number 08 in 2017, the first mechanism is to determine the base split percentage for the contractor, and the government becomes a basis before developing the field. Here are the base splits for the contractor and government: Base Split: Oil production is 57% for the government and 43% for contractor;[70] Gas production is 52% for the government and 48% for contractor.[71]

Variable Split:

After establishing the base split percentage, the percentage will be adjusted again with the pre-defined variable split by Indonesia's Ministry of Energy and Mineral Resources Republic of Indonesia. The percentage split will be adjusted in favor of the contractor. There are ten variable components: (1) Block status; (2) Field Location; (3) Reservoir Depth; (4) Infrastructure; (5) Reservoir Conditions; (6) CO2 Content; (7) H2S Content; (8) API Gravity; (9) Local Content; and (10) Production Phase.[72]

1. Block Status

Block status defined by the stage of the plan of development they provide. Early development stages represent a higher percentage because in the initial stage of changing from an exploration area to a production area, and the uncertainty level is high.

69. Gross Split Production Sharing Contract, Indon. Reg. No. 8/2017.
70. *Id.* art. 5(1)(a).
71. *Id.* art. 5(1)(b).
72. *Id.* art 6(2)(a)-(j).

Plan of Development I: 5%

Plan of Development II: 3%

Plan of Development III: 0%

2. Field Location

The Field location is defined by the location of oil/gas wells, whether in the offshore or onshore area. The highest percentage share is in the offshore area due to the higher risk they have.

Onshore: 0%

Offshore (0<h≤20): 8%

Offshore (20<h≤50): 10%

Offshore (50<h≤150): 12%

Offshore (150<h≤1000): 14%

Offshore (h≤1000): 16%

3. Reservoir Depth

The reservoir depth is determined by the vertical depth of oil/gas wells. The deeper oil/gas wells will have a higher percentage because of the higher risk they have.

Depth ≤2500m: 0%

Depth >2500m: 1%

4. Infrastructure

The infrastructure is defined by the supporting infrastructure in the area; for instance, the highway, port, etc. The more incomplete the facilities, the higher the percentage of the contractor.

Well Developed: 0%

New Frontier Offshore: 2%

New Frontier Onshore: 4%

5. Reservoir Conditions

The reservoir condition, whether conventional or non-conventional, is a determinant. Those that are in the coal seam or shale will get a higher percentage because of the level of difficulty and the cost, which tends to be more expensive.

Conventional: 0%

Non-Conventional: 16%

6. CO2 Content (%)

The CO2 content as defined by the percentage of CO2 in the area will also be a determinant. The higher the percentage of CO2, the contractor will get a higher split. The consideration is because of the difficulty of removing the CO2 that will be released from the reservoir.

<5: 0%

5≤x<10: 0.5%

10≤x<20: 1%

20≤x<40: 1.5%

40≤x<60: 2%

x≥60: 4%

7. H2S Content (ppm)

A greater H2S content introduces greater risk but increases the contractor's share (measured in ppm H2S).

<100: 0%

100≤x<1000: 1%

1000≤x<2000: 2%

2000≤x<3000: 3%

3000≤x<4000: 4%

x≥4000: 5%

8. API Gravity

<25: 1%

≥25: 0%

9. Local Content

The contractor is encouraged to benefit the host country's social welfare through local content engagement.

30≤x<50: 2%

50≤x<70: 3%

70≤x<100: 4%

10. Production Phase

The production phase is determined by the efforts in obtaining the oil and gas; the higher split goes to the enhanced oil recovery method which has to put an extra effort into it to maximize the production in that area.

Primary: 0%

Secondary: 6%

Tertiary: 10%

Additionally, the Production Sharing Contract's Gross Split is a progressive split, determined by the oil/gas price and cumulative production.

Progressive Split:

The progressive split components consist of crude oil price and oil and gas cumulative production.[73]

1. Oil Price

The oil price split is determined by a formula created by the Indonesian government and the Indonesian crude price determined by the Ministry of Energy and Mineral Resources Republic of Indonesia.

Oil Price (US$/Barrel): (85-Indonesian Crude Price) x 0.25

2. Gas Price

The gas price split is determined by a formula created by the Indonesian government, and the Indonesian gas price determined by the Ministry of Energy and Mineral Resources Republic of Indonesia.

Gas Price (<7 US$/MMBTU): (7- Actual gas price) x 0.25

Gas Price (7-10 US$/MMBTU): 0

Gas Price (>10 US$/MMBTU): (10-Actual gas price) x 2.5

3. Oil and gas cumulative production

Oil and gas cumulative production determined by the cumulative production in MMBOE (Million Barrels of Oil Equivalent)

73. *Id.* art. 6(4)(a)-(b).

<30 MMBOE: 10%
30≤x<60 MMBOE: 9%
60≤x<90 MMBOE: 8%
90≤x<125 MMBOE: 6%
125≤x<175 MMBOE: 4%
≥175 MMBOE: 0%

In sum, the final formula to calculate contractor's split:

Contractor's Split = Base Split + Total Variable Split + Total Progressive Split

The new production sharing contract in Indonesia was developed to increase efficiency and government revenue.

Since 2015, government revenue from oil and gas production has been lower than the cost recovery. To increase revenue, the Ministry of Energy and Mineral Resources has focused on achieving a more natural efficiency by reducing the burden of cost recovery, increasing income, and minimizing bureaucracy.

Indonesia's renewed focus has manifested itself in profound interest and development. Under the old PSC Cost Recovery regime in 2015-2016 the government offered twenty-two oil and gas fields and received zero investment interests. Currently, under the new PSC Gross Split regime there are sixteen oil and gas fields using the PSC Gross Split scheme in Indonesia, with competitive bid-winners including ENI Indonesia, Lion Energy, Mubadala Petroleum, aka Energi Indonesia, and Pertamina. These results reflect meaningful improvement.

3.4 Ghana

Ghana's petroleum agreement is a hybrid of elements of the Royalty/Tax, Production Sharing, State Participation, and Additional Oil Entitlement (AOE) dependent on the Rate of Return (ROR) Model.

Ghana offers only one type of petroleum contract. The royalty/tax and production sharing hybrid is the sole contract template that governs the petroleum operations by the contractor.[74] The State does not offer contract

74. The Petroleum (Exploration and Production) Act, 2016 (Act 919) (Ghana) defines the contract provisions that can be negotiated by the Minister on behalf of the State. Section 10(14)(a) requires that in its petroleum agreements, the State must hold a carried interest and a participating interest. Section 85(2) requires the contractor to pay royalties as prescribed or in accordance with the petroleum agreement. Section 87 requires the contractor, subcontractor, licensee, and Corporation to pay tax. Section 89 asserts that the State is entitled to a portion

options and therefore, a typical PSC, concession and risk service contract types are unavailable in Ghana.

The terms of petroleum agreements executed by Ghana over the years were determined by the provisions of petroleum exploration and production laws.[75] The Model Petroleum Agreement (MPA), has evolved over time but its form as a tax/royalty and production sharing model has not changed. The MPA's 2019 revisions reflect the changes in laws since 2000. The major changes included an edit to the language of the MPA to reflect the express provision of the Income Tax Act, 2015 (Act 896) which requires that petroleum operations be taxed on separation operation basis (i.e., ring fencing basis).[76] The 2019 MPA also provided clarity on Additional Oil Entitlement (AOE).[77]

In Ghana, like most jurisdictions in the world, minerals are owned by the State.[78] This means that when the State executes a petroleum agreement with a contractor, the contractor will have no entitlement to the unexploited hydrocarbons until they are produced. The State's ownership right to

---

of a contractor's share of petroleum produced from each field on the basis of the after-tax inflation-adjusted rate of return that the contractor achieved with respect to each field.

75. Income Tax Act, 2016 (Act 896) (Ghana). Throughout Ghana's history, it has promulgated legislation to outline the obligations of oil and gas producers in Ghana. Both before and immediately after Ghana's independence in 1957, Ghana enforced oil and gas contract laws. *See generally,* Mineral Oil Pre-emption Ordinance (Cap. 154) (Ghana); Minerals Ordinance (Cap. 155) (Ghana); and the Tema Town and Port (Acquisition of Land) Ordinance, 1952 (No. 38) (Ghana). Between Ghana's Independence in 1957 and 1984, the contractual provisions of petroleum agreements were largely guided by the provisions of the Minerals Act of 1962 (Act 126), which repealed Cap. 155, 154, and No. 38). FAOLEX DATABASE, Minerals Act, 1962 (Act 126), https://faolex.fao.org/docs/pdf/gha40883.pdf (last accessed Apr. 19, 2023). The promulgation of Petroleum (Exploration and Production) Law, 1984 (PNDCL 84) repealed Act 126. PNDC Law 84, however, reinforced the tax/royalty and production sharing model of Ghana's petroleum agreements. Currently, the laws in force that regulate petroleum operations and agreements are the Petroleum (Exploration and Production) Act, 2016, (Act 919) (Ghana). Act 919 also reinforces the tax/royalty and production sharing model of Ghana's petroleum agreements.

76. Income Tax Act, 2015 (Act 896) (Ghana), § 64.

77. *See* Ghana Nat'l Petrol. Corp., Model Petrol. Agreement of Ghana, pp. 33-42, https://www.petrocom.gov.gh/wp-content/uploads/2018/12/ghana_model_petroleum_agreement1.pdf (last accessed Apr. 19, 2023) (*amended by* Amend. No. 1 to Petrol. Agreement, https://www.petrocom.gov.gh/L&C_folder/Pet_register/south_deepwater_tano/Amendment%20South%20Deepwater%20PA.pdf (last accessed Apr. 19, 2023).

78. Minerals, including petroleum, in their natural state, found in the territories of Ghana whether onshore or offshore, belong to the Republic. *See* Petroleum (Exploration and Production) Act, 2016 (Act 919) (Ghana), § 3; *Id.* at 1.

hydrocarbons in their natural state is clearly stated in the petroleum agreement.[79]

The implication of the State Ownership provision is that the contractor will not be able to recover any of its cost until such a time that production has commenced from the contract area and title in the contractor's share of the produced hydrocarbons has passed to the contractor in accordance with the terms of the contract. This means that none of the costs for exploration or appraisal can be recovered if exploration encounters a dry hole. The contractor will equally not recover any cost it accumulates if it abandons or relinquishes the contract at any stage in the exploration and development process. Cost can only be recovered against contractor's share of hydrocarbons produced from the contract area.

Crude oil sharing is fundamental to the concept of cost recovery. The contractor recovers its cost from revenue realized through the sale of crude oil produced from the contract area. The terms of the petroleum agreement determine how crude oil is shared and how lifting is done by the parties.[80] Gross production of crude oil is distributed among the parties in the following sequence;[81] a contractually agreed percentage is delivered to the State as Royalty,[82] after which, crude is delivered to the Ghana National Petroleum Corporation (GNPC) in an amount derived from Sole Risk Operations;[83] the remaining crude oil is then distributed to the Contractor and GNPC on the basis of their respective interests.[84] Subject to the Petroleum Act,[85] the State's Additional Oil Entitlement, if any, is distributed to the State out of the

---

79. *See* Ghana Nat'l Petrol. Corp., Model Petrol. Agreement of Ghana, p. 1, https://www.petrocom.gov.gh/wp-content/uploads/2018/12/ghana_model_petroleum_agreement1.pdf (last accessed Apr. 19, 2023).

80. Lifting crude is done "in accordance with the terms of the petroleum agreement and the Crude Oil Lifting Agreement (COLA) for each field." Pub. Int. and Accountability Comm., 2020 Semi-Ann. Rep. on the Mgmt. of Petrol. Revenues, p. 48,

81. Ownership originates with the Republic. "All Petroleum existing in its natural state within Ghana is the property of the Republic of Ghana and vested in the President on behalf of and in trust for the people of Ghana. Ghana Nat'l Petrol. Corp., Model Petrol. Agreement of Ghana, p. 1, https://www.petrocom.gov.gh/wp-content/uploads/2018/12/ghana_model_petroleum_agreement1.pdf (last accessed Apr. 19, 2023).

82. *Id.* at 33.

83. *Id.*

84. *Id.*

85. Petroleum (Exploration and Production) Act, 2016 (Act 919), § 89. "The Republic is entitled to a portion of a Contractor's share of petroleum produced from each Field on the basis of the after-tax inflation-adjusted rate of return that the Contractor achieved with respect to each Field."

Contractor's share of crude oil determined under the Petroleum (General) Regulations.[86]

Subject to the rate of royalty agreed in the Petroleum Agreement (PA), the GNPC lifts its share of the crude oil produced in respect of the royalties due. Royalties become due when the contractor produces crude oil from the contract area. It is calculated based on actual production using the royalty rate agreed by the parties. Royalty rates vary from one PA to another.[87] Royalty rates on crude oil are usually higher than those on gas.[88] The actual rate of royalties is the subject of negotiations between the State and the contractor and as a result, the MPA leaves the section for royalties open to allow the parties to negotiate.[89] The major factor for the State in these negotiations is the degree of risk inherent to the petroleum operation. Under the terms of the PA, the GNPC may elect to receive cash in lieu of its royalty shares of crude oil.

Principal Contract Terms for Oil and Gas Production in Ghana

It is difficult to estimate how much crude oil GNPC is entitled to, under sole risk. In practice, this is very rarely implemented as the parties usually cooperate with each other and have the shared objective of maximizing the recovery potential of the contract area. GNPC, as representative of the State, reserves the right to explore, appraise, and develop the contract area outside of the work program of the contractor at its own cost and sole risk.[90] Outside

86. Petroleum (Exploration and Production) (General) Regulations, L.I. 2359, Regul. 75(1)-(4)–Additional Oil Entitlement, https://www.petrocom.gov.gh/wp-content/uploads/2019/12/PETROLEUM-EXPLORATION-AND-PRODUCTION-GENERAL-REGULATIONS-2018-L.I-2359.pdf (last accessed Apr. 19, 2023).

87. *Compare* Petroleum Agreement, Deepwater Tano, https://www.tullowoil.com/application/files/2015/8517/6346/deepwater-tano-contract-area-pa.pdf (last accessed Apr. 20, 2023) where the royalties negotiated and agreed in respect of the Deepwater Tano Contract Area between the State and the Contractors led by Tullow Oil was at 5% and 4% for oil at API 18°, and 3% for Non-associated Gas *with* Petroleum Agreement, West Cape Three Points Block Offshore Ghana, https://www.sec.gov/Archives/edgar/data/1509991/000104746911001716/a2201620zex-10_1.htm (last accessed Apr. 20, 2023) where the Agreement negotiated and agreed in respect of the West Cape Three Block between the State and the Contractors led by Kosmos Energy was at 7.5% and 5% for oil at API 20°, 5% for Non-associated Gas.

88. *Id.*

89. Ghana Nat'l Petrol. Corp., Model Petrol. Agreement of Ghana, p. 33, https://www.petrocom.gov.gh/wp-content/uploads/2018/12/ghana_model_petroleum_agreement1.pdf (last accessed Apr. 19, 2023).

90. *Id.* at 30.

of the work program, the GNPC may drill deeper wells and develop new horizons.[91]

The State's Participating interest is the total of the State's carried interest and has a set minimum of fifteen percent and an optional, capped paying interest that arises after the contractor declares the well is capable of commercial production.[92] The crude oil remaining after distribution of royalty crude oil and sole risk entitlement is then shared among the parties in accordance with their respective interest holdings. Initially, the crude lifted by the contractor is lifted on behalf of GNPC as a repayment of advances made to the Corporation by the contractor under the terms of the PA.[93] However, the contractor may receive advances under the PA through payment on behalf of GNPC's share of cash calls towards development and production expenditure.

The oil distributed to the State is not determined until the AOE crystallizes. AOE is a tax which allows the State to share in contractors' profits. In accordance with the law and the PA, at any time, the State is entitled to a portion of Contractor's share of Crude Oil produced from each separate area on the basis of the contractor's after-tax post-inflation adjusted rate of return ("ROR").[94] The Contractor's ROR is calculated on its Net Cash Flow ("NCF") and determined separately for each Development and Production Area at the end of each month in accordance with a prescribed formula. AOEs can be taken either in cash or in kind. AOE is triggered when the contractor achieves a defined RoR.[95]

---

91. *Id.*

92. Petroleum (Exploration and Production) Act, 2016 (Act 919) (Ghana), § 10(14)(a).

93. *See* Ghana Nat'l Petrol. Corp., Model Petrol. Agreement of Ghana, pp. 33-34, https://www.petrocom.gov.gh/wp-content/uploads/2018/12/ghana_model_petroleum_agreement1.pdf (last accessed Apr. 19, 2023).The barrels of crude oil that can be lifted by the contractor in lieu of cash payment by GNPC is capped. The Joint Operating Agreement negotiated and executed separately from the Petroleum Agreement set out the terms including the barrels to be lifted by the contractor.

94. *See* Petroleum (Exploration and Production) Act, 2016 (Act 919) (Ghana), § 89; Ghana Nat'l Petrol. Corp., Model Petrol. Agreement of Ghana, p. 34, https://www.petrocom.gov.gh/wp-content/uploads/2018/12/ghana_model_petroleum_agreement1.pdf (last accessed Apr. 19, 2023).

95. ROR computations require a contractor to determine the returns from the petroleum operations based on cost allowable under the MPA, 2019. The portion of the contractor's allowable cost that have been recovered in any given quarter or year becomes a key variable aside revenue in the determination of returns which is further incorporated in the ROR calculation. AOE calculation which is dependent on ROR and NCF requires a cost recovery. *See* Ghana Nat'l Petrol. Corp., Model Petrol. Agreement of Ghana, pp. 33-37, https://www.

Ghana's petroleum agreements define "Petroleum Costs" broadly as "all expenditures made and costs incurred in conducting Petroleum Operations hereunder determined in accordance with the Accounting Guide [contained in the PA.]"[96] The PA's cost recovery process continues throughout the life of the PA or petroleum operations. The PA permits petroleum costs to be recovered from all the revenue realized from the sale of contractor's share of crude oil. Cost recovery is markedly different from the PSC system of cost recovery which typically earmarks a percentage of crude oil production as cost oil from which all cost deductions are made.[97]

The Ghana National Petroleum Corporation is only liable to contribute to Petroleum Costs incurred during development operations to the extent of its additional participating interest acquired in such development and production area and the expenditures attributable to that Additional Participating Interest.[98] It is also liable in respect of production operations (excluding costs for decommissioning) in any development and production area to the extent of its initial participating carried interest,[99] and any additional participating interest.[100]

Until the Contractor has notified GNPC that it wishes to appraise a discovery, GNPC may notify the Contractor that it will, at its Sole Risk, appraise that discovery, unless within thirty (30) days of such notification from GNPC, Contractor elects to commence to appraise that discovery within its own Work Program.[101] Where an appraisal undertaken at the sole risk of GNPC results in a determination that a discovery is a commercial discovery, the Contractor may develop it upon reimbursement to GNPC of all expenses incurred in undertaking the appraisal and after arranging with the Corporation satisfactory terms for the payment of a premium. Such premium is not considered as petroleum costs.[102]

---

petrocom.gov.gh/wp-content/uploads/2018/12/ghana_model_petroleum_agreement1.pdf (last accessed Apr. 19, 2023).

96. *Id.* at 6.

97. Cost recovery is field ring fenced described in the MPA, 2019 as separate petroleum operation or developed area within the contract area. The developed area is the portion of the contract area where discovery has been made and commerciality declared as well as PoD approved for that discovery. Every discovery made for which a separate PoD is approved by the Minister for its development shall constitute a ring fence area within the big contract area.

98. Model Petroleum Agreement, 2019, Art. 2.7(a).

99. *Id.*, Art. 2.7(b)(i).

100. *Id.*, Art. 2.7(b)(ii).

101. *Id.*, Art. 10.1.

102. *Id.*, Art. 10.2.

The Contractor is granted the right under its Agreement[103] to make direct payments outside of Ghana from its offices abroad and elsewhere to its employees and subcontractors, for wages, salaries, purchase of goods, and performance of services for petroleum operations, and such payments are considered as petroleum costs.[104]

Petroleum costs incurred with respect to the contract area has no bearing on allowable or non-allowable costs under any other contract area or Contractor's eligibility or otherwise for deductions in computing Contractor's net income from petroleum operations for income tax purposes in any other contract area.[105] Further, and similarly, petroleum costs incurred in any other contract area shall have no bearing on allowable or non-allowable costs in respect of the Contract area or Contractor's eligibility or otherwise for deductions in computing Contractor's net income from petroleum operations for income tax purposes in respect of the Contract area.[106]

Where a Contractor carries out exploration activity within the development and production area, the cost of the exploration activities shall be "ring-fenced," and recovered from the production revenues of the prospect.[107] Costs emanating from the prospect cannot be charged to the existing commercial discovery or discoveries within the development and production area.[108] In the event there is a commercial discovery, the exploration cost is treated as petroleum cost.[109]

Cost recovery under the PA is an entirely different arrangement from the fiscal regime. the PA expressly provides that the cost and expenses set forth in the PA shall be for the purpose of determining allowable or non-allowable costs and expenses only and shall have no bearing on contractor's eligibility or otherwise for deductions in computing contractors net income from

103. *Id.*, Art. 14.
104. *Id.*, Art. 14.6.
105. *Id.*, Art. 17.9
106. *Id.*
107. Petroleum (Exploration and Production) (General) Regulations, L.I. 2359, Regul. 29(1)-(4)–Additional Oil Entitlement, https://www.petrocom.gov.gh/wp-content/uploads/2019/12/PETROLEUM-EXPLORATION-AND-PRODUCTION-GENERAL-REGULATIONS-2018-L.I-2359.pdf (last accessed Apr. 19, 2023) (*amended by* Petroleum (General) (Amendment) Reguls., Regul. 5(3) and 5(4)(b)).
108. *Id.* Regul. 29.
109. *Id.*

petroleum operations for income tax purposes.[110] The contractor's rights and obligations under the PA is different from its rights and obligations under the applicable tax laws of Ghana. Notwithstanding the right of the contractor to recover its cost under the PA, it has an obligation to pay taxes on its operations. These two must be viewed separately as the rules applicable under the two regimes are different. Cost recovery is entirely regulated by the provisions of the PA whilst taxes are determined by the fiscal regime stated in the PA. Ordinarily, the cost recoverable under the PA ought to be tax deductible, and unrecoverable cost ought not to be deductible under tax rules. In practice, this is not always the case. There are exceptional instances where costs that are not recoverable under the PA are tax deductible.

Petroleum Costs recoverable under PA

The PA specifies the recoverable costs. The only cost a contractor may charge against petroleum income are those which are provided for under the PA as recoverable. Any other cost outside the scope of the defined recoverable cost in the PA will not be recoverable. The accounting guide to the PA establishes the methods for determining charges and credits applicable to operations under the PA.[111]

Expenditures relating to petroleum operations are also classified into five categories: (1) exploration expenditures, (2) development expenditures, (3) production expenditures, (4) service costs, and (5) general and administrative expenses.[112]

Costs unrecoverable under PA

The PA sets out those costs that shall not be recoverable against contractors' revenue realized from its share of crude oil.[113] This category includes costs incurred by the Contractor before the effective date of the

---

110. Ghana Nat'l Petrol. Corp., Model Petrol. Agreement of Ghana, Annex 2 pp. 13, https://www.petrocom.gov.gh/wp-content/uploads/2018/12/ghana_model_petroleum_agreement1.pdf (last accessed Apr. 19, 2023).

111. *See Id.* p. 2. The PA allows the contractor to charge the following allowable cost to the petroleum accounts: Surface rental costs, labor and associated costs, transportation costs, charges for services, material and equipment costs, rentals, duties and other assessments insurance and losses (including deductibles and expenses), legal expenses training expenses, general and administrative expenses, utility costs, office facility charges, communication charges, ecological and environmental charges, abandonment and site restoration costs, and other cost necessary for the petroleum operations. *Id.* p. 8.

112. *Id.* pp. 5-7.

113. *Id.* p. 12.

Agreement,[114] commission paid to intermediaries by the contractor except where the contracts for such goods and services includes a commission for intermediaries and are approved by the Operating Committee,[115] charitable donations not approved by the Commission,[116] interest incurred on loans by the contractor as well as other borrowing cost,[117] costs (including duties) arising from the marketing or processing or transportation of petroleum beyond the delivery point,[118] cost of any bank guarantee under the PA, and any other amounts spent on indemnities with regard to non-fulfillment of contractual obligations,[119] premium paid as a result of GNPC exercising a sole risk option,[120] and costs of any nature incurred in connection with any consultation, arbitration or sole expert process under the dispute resolution mechanism under the PA,[121] as well as fines, penalties and interests due pursuant to any law or regulation imposed by a final and unappealable decision of a competent administrative body or judicial body.[122]

It further includes costs, damages and other liabilities incurred as a result of relevant gross negligence or willful misconduct of the Contractor or Operator,[123] various taxes,[124] and costs incurred by the Contractor under contracts or amendments thereto that were subject to approval by either the Operating Committee or the Commission, but were not approved,[125] undocumented costs,[126] and finally, any bonus payments payable by the Contractor under the Agreement to the State, any other governmental body, GNPC, or any of its affiliates.[127]

Thin Capitalization

Interest incurred on loans by the contractor is not cost recoverable under the PA. Notwithstanding, it is tax deductible under the tax laws of Ghana. However, interest on loans provided by a related party to a contractor, is

114. *Id.* § 3.17.1(a)
115. *Id.* § 3.17.1(b)
116. *Id.* § 3.17.1(c)
117. *Id.* § 3.17(d)
118. *Id.* § 3.17.1(e)
119. *Id.* § 3.17.1(f)
120. *Id.* § 3.17.1(g)
121. *Id.* § 3.17.1(h)
122. *Id.* § 3.17.1(i)
123. *Id.* § 3.17.1(j)
124. *Id.* § 3.17.1(k)
125. *Id.* § 3.17.1(l)
126. *Id.* § 3.17.1(m)
127. *Id.* § 3.17.1(n)

subject to thin capitalization rules and where interest exceeds the threshold, the excess is not tax deductible or recoverable. The thin capitalization rules in Ghana, limits interest deduction to a Three-to-One (3:1) debt-to-equity ratio.

Capital Allowance

The contractor is entitled to capital allowances for all capital expenditure in place of depletion, depreciation, and amortization (DD&A) of cost. The *Income Tax Act*, 2015 (Act 896) requires that a revenue expenditure or a capital expenditure during exploration and development operations should be placed in a single pool. The contractor is entitled to carry forward the balance in the pool from year to year until production commences when the balance in the pool of exploration and development expenditure at that time is allowed to be capitalized for a grant of capital allowances to pay for expenditures.[128] Capital allowance is granted with respect to the petroleum operation on a ring-fenced basis and at the rate of twenty percent on straight line basis.[129] The grant of capital allowance in place of DD&A at a rate of twenty percent implies that the contractor can only recover its exploration and development expenditure over a five (5) year period from petroleum income.

Deductibility

Deductibility of cost is allowed on a general principle that cost incurred in petroleum operations is wholly, exclusively, and necessarily incurred in the acquisition or improvement of a valuable asset used in the operation; or is wholly, exclusively and necessarily incurred in acquiring services or facilities for the operation.[130]

Under the general principles of deductibility, the costs which are unrecoverable or disallowed under the PA may qualify as deduction against petroleum income. Specific costs allowable for deductions include annual rental charges and royalties paid, contributions to and other expenses incurred in respect of a decommissioning fund, as well as any other amount incurred directly by that person during petroleum operations. On the other hand, many expenses are not deductible or recoverable.[131]

128. Income Tax Act, 2015, Act 896 (Ghana), § 65.
129. *Id.* § 67.
130. *Id.*
131. The following expenditure are not deductible or recoverable: Research and development expenditures, related parties transactions not priced at arm's length, a bonus

Carry Over of Losses

The contractor is allowed to carry over unrelieved loss[132] for a maximum of five years.[133] Pre-production losses is allowed to be carried over and deducted from future income realized from petroleum operations. Pre-production losses excludes exploration and development expenditure which are specifically required to be put in a pool for capitalization and subsequent grant of capital allowances. The contractor's right to carry over losses is not limited to pre-production losses only but applicable to losses incurred during production.

Income Tax

Income tax applies to only the net income of a contractor after all cost recoverable or deductible and allowance have been made under the Income Tax Act. The *Income Tax Act* imposes a petroleum income tax on the income of a contractor from petroleum operations. The PA typically specifies the rate of income tax.[134] PAs executed when the *Petroleum Income Tax Act,* 1987 was in force had an income tax rate of 35%. The *Income Tax Act,* 2015 still retains the petroleum income tax of 35%.[135]

Stabilization Clause and its impact on Cost Recovery

Freezing stability clauses are important to early petroleum agreements. With stability clauses, the State guarantees the terms and conditions of the PA from the effective date through its entire term, including guarantees of the fiscal regime, legislation, and regulations specifically stated in the PA. Amendments to the PA require mutual agreement. It is further provided that the State, through its departments and agencies, shall support the agreement

---

payment made in respect of the grant of the petroleum right, and expenditures incurred as a consequence of a breach of a petroleum agreement.

132. As determined in accordance with International Financial Reporting Standards (IFRS) and audited per International Auditing Standards in force at financial year end of the contractor.

133. Income Tax Act, 2015, (Act 896) (Ghana), § 17.

134. Ghana Nat'l Petrol. Corp., Model Petrol. Agreement of Ghana, p. 43, https://www.petrocom.gov.gh/wp-content/uploads/2018/12/ghana_model_petroleum_agreement1.pdf (last accessed Apr. 19, 2023).

135. Income Tax Act, 2015, (Act 896) (Ghana), § 63(2), First Schedule.

and "shall take no action to prevent or impede the due exercise and performance of the rights and obligations of the parties [to the PA]."[136]

Stabilization clauses have worked so far as experience has shown that all parties to previously signed PAs have adhered to the terms therein; however, this is not without regular challenge from state agencies. The main form of challenge has been in the form of the Ghana Revenue Authority and the Petroleum Commission seeking to apply new legislation to existing contracts with stability clauses. Several IOCs are listed companies that carry warning statements to their shareholders about such ongoing disputes in their annual reports. The Government of Ghana has repealed some legislation, but the repealed legislation has continued to apply to PAs with freezing stabilization clauses. An example is the fact that though the *Petroleum Income Tax Act*, 1987 (PNDCL 188) and the Petroleum (Exploration and Production) Act, 1984 (PNDCL 84) have been repealed, they've been saved to the extent of their applicability to existing PAs. The existence of a stability clause in the PA brings predictability and certainty in the cost recovery in theory, thereby allowing the contractor to project and forecast the payback period of the investment.

Challenges with Cost Recovery

Contractors expend time and money to resolve disputes. Interpretation of provisions in the PA have occasionally led to disagreement between agencies of the State, often the GNPC and Ghana Revenue Authority, and the contractor. These parties disagree on key terms such as the AOE crystallization date and tax deductibility on expenditures.[137]

The Ghana Revenue Authority (GRA) is the State institution established by law with the mandate to undertake tax administration in Ghana.[138] All taxes and royalties due to the State are collected by GRA on behalf of the State.[139] In carrying out its mandate, GRA subjects the provisions of the PA to interpretation to determine if a particular item of expenditure is allowable or disallowable. Expenses associated with derivative contracts are *stricto*

---

136. Ghana Nat'l Petrol. Corp., Model Petrol. Agreement of Ghana, p. 75, https://www.petrocom.gov.gh/wp-content/uploads/2018/12/ghana_model_petroleum_agreement1.pdf (last accessed Apr. 19, 2023).

137. The PA provides a formula to guide the calculations and determination of AOE. The application and interpretation of the formula has often led to a dispute between the State represented by GNPC and GRA and the contractor group. The effect of the GNPC and GRA's interpretation is an early payment of AOE while the contractor group interpretation leads to late crystallizations of AOE payment.

138. Ghana Revenue Authority Act, 2009 (Act 791) (Ghana), § 1(2), 2(a).

139. *Id.* § 3(a).

sensu not a petroleum expenditure per se but are necessary expenditures incurred generally by petroleum companies as a risk management mechanism to respond to market fluctuations in crude prices. Such and similar expenses have often been a subject of interpretative dispute.

GRA does not have the mandate or the power to approve expenditure under the PA. However, under its mandate, it may disallow expenditure. Contractors may seek redress under the dispute resolution clauses contained in the PA.[140]

Interpretative dispute concerning ring-fencing is no longer an issue following the enactment of the *Income Tax Act*, 2015 and the revision of the Model Petroleum Agreement in 2019,[141] for contracts after those laws were enacted. The language of the PA lends itself to varying interpretation between GRA and the contractors as to the applicability of ring-fencing. GRA viewed the pre-2019 MPA as field ring fence while contractors held the position that the ring fencing was inapplicable to the pre-2019 MPA.

The State took notice of these implementation challenges with the PA and subsequently enacted laws that expressly addressed the challenges as discussed above. The State addressed these challenges with the enactment of the Petroleum (Exploration and Production) Act, 2016, (Act 919) and its attendant regulations, as well as the Income Tax Act, 2015 (Act 896). Further to the enactments of laws, the State has equally redrafted its MPA in 2019 to adapt to the changes made in the fiscal regime following the enactment of Act 919 and Act 896.

The stabilization clauses in the executed PAs, however, makes these new enactments inapplicable to the previously executed PAs and therefore do not address the issues with those PAs. However, the parties have for the most part, found a way to mutually work together to avoid litigating the dispute.

Conclusion

Cost recovery in Ghana's petroleum industry is best viewed from two standpoints. First, it is a PA regime. The PA clearly lists the costs that can be charged to petroleum operations under its terms. Exploration and development expenditures are capital items which are recoverable through the grant of capital allowances under the fiscal regime. The PA identifies some expenditure as recoverable against petroleum revenue or income while others are not. It is imperative to note the nexus between cost recovery under the PA and the additional oil entitlement computation. Second, the PA

140. Model Petroleum Agreement, 2019, art. 19.
141. Income Tax Act, 2015, Act (896) (Ghana), § 64.

defines the fiscal regime applicable to upstream petroleum operations. The stability clauses in the earlier PAs freeze the fiscal regime which cannot be varied during the contract term of the PA. Costs that are not deductible or recoverable under the PA may be recoverable under the tax regime. The *Income Tax Act*, emphasizes cost recovery on the basis of separate petroleum operation or ring-fencing. The PA is always a negotiated contract and therefore gives the parties a fair opportunity to agree on the costs which are recoverable and the rules that should govern cost recovery as a way of ensuring that the process is fair to all parties.

3.5. Malaysia

a) Brief explanation about the evolution of PSCs and cost recovery in your jurisdiction

In the mid-1970s Malaysia nationalized its oil production and replaced the concession system with the current Production Sharing Contract model.[142] Since 1974, The Malaysian oil and gas industry has been governed by PETRONAS.[143] Prior to 1974, the state government granted oil companies petroleum concessions.[144] These concessions granted oil companies the exclusive right to discover and develop oil and gas reserves. In exchange, these oil companies would pay the government royalties and taxes.[145] It came to an end on April 1, 1975, when the Petroleum Development Act (PDA) of 1974 granted PETRONAS possession of crude oil and natural gas resources in Malaysia and offshore and exclusive rights to discover and extract petroleum.[146] This decision provided significant incentives to international oil firms to continue oil production and investment in oil and gas exploration without denying companies sustainable rent capture and jeopardizing national interests.[147]

PETRONAS was given complete flexibility to set the policy, form, terms, and conditions of all new deals, including those intended to replace the ones that were abolished, in order to accommodate changing conditions in the oil

---

142. *See* Eduardo G. Pereira et al., *Host Granting Instrument Models: Why Do They Matter and for Whom*, 6 OIL & GAS, NAT. RESOURCES & ENERGY J. 23 (2020).

143. *See* Jaginder Singh, T*he Legal Structure and Attendant Problems of the National Petroleum Corporation of Malaysia*, 18 MALAYA L. REV. 125 (1976).

144. Mohamad K. Hamdan et al., Presentation at SPE Asia Pacific Oil and Gas Conference and Exhibition: Enhanced Oil Recovery in Malaysia: Making It a Reality (2005).

145. *Id.*

146. *Id.*

147. *See* Eduardo G. Pereira et al., *Host Granting Instrument Models: Why Do They Matter and for Whom*, 6 OIL & GAS, NAT. RESOURCES & ENERGY J. 23 (2020).

industry.[148] PETRONAS is the authority for all PSCs, the partnerships of which are formed from various multinational oil and gas firms.[149] The 1974 Petroleum Regulations, give PETRONAS the authority to grant licenses for activities related to petroleum exploration and production and carry out the provisions of the PDA.[150] In this case, any oil and gas firms intending to conduct hydrocarbon extraction in Malaysia or other oil exploration activities with PETRONAS shall execute the PSC.

Since its inception in 1976 to replace the concession-based scheme, the Production Sharing Contract (PSC) has evolved.[151] The PSC fiscal terms are now adjusted to match the opportunities available, allowing PETRONAS and investors to share profit oil and profit gas to the maximum extent possible. Oil companies (Contractors) are in charge of exploring, developing, and producing hydrocarbon resources in Malaysia under the terms of the PSCs. Although the Contractors bear the risks of petroleum operations in the contract field, they are entitled to hydrocarbon production.[152]

The first PSC was signed in 1976 with Shell, with modifications made later in 1985. Following that, in 1993, two sets of Deepwater PSCs were added, and in 1995, onshore PSC terms were created.[153] Under the 1985 legislation, Petronas is expected to retain a minimum of 15% equity in production sharing contracts (PSC) with both international and private companies.[154]

PETRONAS requires investors to apply for and obtain a license to engage in exploration and development activities. Citation. PETRONAS and the investors (referred to as contractors) enter a Petroleum Arrangement (PA)

---

148. Bernard Taverne, *An Introduction to the Regulation of the Petroleum Industry: Laws, Contracts and Conventions* (1994).

149. Wan Zulhafiz, *Unfair Contract Terms Act 1977: Does It Provide a Good Model in Regulating Risk Allocation Provisions in Oilfield Contracts in Malaysia?* 8 INT'L J. OF TRADE & GLOB. MKT. 3 (2015).

150. Pereira, *supra* note 148.

151. *Fiscal Terms*, PETRONAS, https://www.petronas.com/mpm/investment-opportunities/fiscal-terms (last accessed Apr. 20, 2023).

152. *Id.*

153. Wan M Zulhafiz Wan Zahari & Farid Sufian bin Shuaib, *The Distribution of Petroleum Resources in Malaysia: Unpacking Federalism*, 13 THE J. OF WORLD ENERGY L. & BUS. 369 (2020).

154. Malaysia, UNITED STATES ENERGY INFORMATION ADMINISTRATION, https://www.eia.gov/international/content/analysis/countries_long/Malaysia/archive/pdf/malaysia_2014.pdf (last updated Sep. 29, 2014).

contract under which one of the parties is known as the operator.[155] The Production Sharing Contract (PSC) is the most common type of PA contract that is still in use today. It outlines the terms, conditions, rights, and duties of the parties involved. Some essential provisions are included in a conventional PA contract such as the scope and duration of the contract, fiscal terms as well as the cost recovery method, a map of the contract's location, work obligations as well as a bare minimum of financial demands, contractors' involvement rights and responsibilities, supervision during the course of the operation, requirements for work-planning and financial budgeting, and determination of the value of hydrocarbons and the technique of segregation.[156]

For PSCs, there are two profit-sharing and cost-recovery models. The first is focused on production rate/volume (i.e., 1976, 1985, and Deepwater PSCs), where the resource owner's take increases as the project's economic health improves. The second is profitability-based (i.e., R/C PSC (Revenue over Cost PSC)), where the resource owner's take increases as the project's economic health improves (indicated by an R/C index).[157] The majority of current PSCs are focused on an R/C arrangement, with benefit tranches determined by the ratio of revenue to costs incurred, as well as clawback functions.[158]

b) Brief explanation about the challenges and concerns with PSCs and cost recovery in your jurisdiction

Having caught up with the changing times, Malaysia is now facing the danger of losing its natural gas and oil resources. Therefore, Malaysia cannot afford to ignore the need to expand its present marginal resources. At the same time, exploration for further petroleum reserves continues due to the ever-increasing demand for oil for domestic consumption, which is driving up the price of crude oil.[159]

---

155. Regulatory Contracts & Guidelines, PETRONAS, https://www.petronas.com/mpm/regulatory/contracts-guidelines (last accessed Apr. 20, 2023).

156. *Id.*

157. Eugene Thean Hock Lee, *Scope For Improvement: Malaysia's Oil And Gas Sector*, REFSA https://refsa.org/wp-content/uploads/2020/10/pdfslide.net_og-scoping-report-malaysia-final-20130701-compressed.pdf (July, 2013)

158. *Fiscal Terms*, PETRONAS, https://www.petronas.com/mpm/investment-opportunities/fiscal-terms (last accessed Apr. 20, 2023).

159. Mohd Rasheed Khan & Mohd Farizal Farhan Abd Ghafar, *Marginal Fields-Investment Opportunities in Oil & Gas*, AZMI & ASSOCIATES, https://www.inhousecommunity.com/wp-content/uploads/2016/07/v11i1_JURIS_Malaysia.pdf (last accessed Apr. 20, 2023).

For example, according to reports, Malaysia has built more than 100 marginal regions, most of which have not yet been adequately developed.[160] As a result, the costs of growing these marginal crops are equal to the costs of establishing huge fields. Hence, the PSC system may not be desirable to consumers since there may not be adequate oil/gas balance for benefit sharing purposes.[161]

c) Brief explanation about solutions adopted or at least considered to solve the said challenges and concerns

Risk Service Contract

PETRONAS introduced the risk service contract (RSC) regime as part of its ongoing attempts to become more competitive and to lure foreign oil and gas corporations to invest in the country's oil and gas industry. During the development of marginal oil fields, PETRONAS and Contractors engage in a service agreement. The Contractors perform services to PETRONAS in exchange for compensation in the form of royalties.

Among the most significant characteristics of the RSC is that all development expenses, which are like those incurred under the PSC, are advanced up front by the Contractors in accordance with their stipulated participation interests, and the vast majority of these expenditures are tracked and authorized by PETRONAS throughout the operations.

Malaysia has boosted its competitiveness through strategic changes in its tax code. In relation to the Fiscal Model and Cost Recovery Mechanism for the RSC, the Petroleum (Income Tax) Act 1967 was amended in 2011 to include a tax exemption and special treatment for income. Citation. The Prime Minister, Dato' Sri Haji Mohammad Najib bin Tun Haji Abdul Razak proposed further benefits in the 2013 Budget, including that the Act provides for an exemption from corporate taxes of 100 percent for a period of ten years and exemptions from withholding tax and stamp duty on oil and gas public-private partnerships. In addition, during their first three years of operation, liquid natural gas trading firms are entitled to a 100 percent income tax exemption on their statutory income and a cut in the tax paid by multinational corporations operating in marginal oil fields from 38 per cent to 25 per cent.

According to the RSC arrangement, PETRONAS will retain ownership and control over all petroleum resources. Citation. The contractor will only be compensated for services rendered when the petroleum has been economically exploited. Citation. In contrast to the former regime, such

160. *Id.*
161. *Id.*

reparation payments are not subject to petroleum tax under the present administration but rather to Malaysian corporate tax. Citation. In addition, under this arrangement, unlike under the PSC system, the contractor is not compelled to pay a research cess or to make an abandonment commitment, in contrast to the PSC regime.[162]

New PSC Fiscal Terms

Apart from the PSC, three new PSC fiscal terms were introduced recently, i.e., Small Fields Assets (SFA) in 2019, Late Life Assets (LLA) in 2020, and Shallow Water Enhanced Profitability Terms (EPT) in 2021.[163]

1.0 Late Life Assets (LLA)

The LLA commercial arrangement is a more straightforward business structure that utilizes mutual abandonment liability to incentivize contractors and reward output.[164] The LLA contains no cost recovery mechanisms, a straightforward separation of crude oil and natural gas production, no additional payments, no research cess pay-outs or education commitments, as well as a shared financial burden on abandonment.[165] Instead, the LLA arrangement places a premium on cost savings and is made possible by a simpler performance-based compensation scheme.[166]

The entitlement split is based on a fundamental gross production division that includes a 10% cash payment to the government and a predetermined Y per cent of gross output for the Abandonment Cost Commitment ("X"), with the remainder of the entitlement becoming Contactor's Take (100 percent - 10 percent - Y percent).[167]

---

162. A "cess" is a form of tax on tax. The government levies a cess on specific-purpose taxes until the government raises sufficient funds to achieve the specific purpose. A cess is imposed as an additional tax and is different from usual taxes and duties like excise and personal income tax.

163. *Fiscal Terms*, PETRONAS, https://www.petronas.com/mpm/investment-opportunities/fiscal-terms (last accessed Apr. 20, 2023).

164. *Late Life Assets (LLA) PSC Terms*, PETRONAS, https://www.petronas.com/mpm/investment-opportunities/fiscal-terms/LLA (last accessed Apr. 20, 2023).

165. *Id.*

166. *Id.*

167. *Id.*

Three (3) critical criteria are identified in the conditions of this commercial agreement:

- Total Abandonment Cost Estimate ("A"),
- Abandonment Cost Commitment ("X"), and
- Fixed Percentage of Gross Production (Y%).

In line with the Petroleum Development Act of 1974, there will be a cash payment. PETRONAS will withhold a maximum of 10% from cash payments to the government to cover administrative costs. Contractors are entitled to a part of the Fixed Percentage (Y%) for the purpose of making an Abandonment Cess Payment as a fund to meet the Abandonment Cost Commitment (X%). Meanwhile, the Fixed Percentage is sometimes referred to as Y per cent. PETRONAS will be entitled to collect the Fixed Percentage as part of its rights once the Abandonment Cost Commitment is met.[168]

Contractors will receive the balance of the remaining incentives (Contractor's Take), which shall cover all expenses incurred by Contractors in connection with petroleum operations, including all taxes due under the Petroleum Income Tax Act (PITA) and Export Duty (if applicable) under Customs Regulation. Contractors are responsible for paying any taxes, whether collected by the Federal, State, or municipal governments. Contractors are personally accountable under Malaysian law and must do so at their own expense.[169]

Contractors who use the LLC Model receive numerous benefits, including administrative simplicity in the absence of cost recovery, compensation for extending the economic life of the asset through prudent cost control, the ability to earn more money as production increases, and a dollar saved is a dollar made.[170]

2.0 Small Field Assets (SFA)

The term Small Field Assets (SFA) refers to an upgrade of the PSC fiscal model that implements a new fiscal model that is clear and simple. Moreover, it facilitates the streamlining of operational procedures by empowering contractors in specific areas such as yearly planning, the analysis of Field Development Plans (FDP), and the procurement process.[171]

---

168. *Id.*
169. *Id.*
170. *Id.*
171. *Small Field Assets (SFA) PSC Terms*, PETRONAS, https://www.petronas.com/mpm/investment-opportunities/fiscal-terms/SFA (last accessed Apr. 2023).

Several fundamental elements of SFA, such as contract term (which will vary depending on the asset and include abandonment work), will remain in place for 10 to 15 years after the contract is signed (depending on the asset).[172]

Apart from that, aspects of the contract scope such as the development, production, and abandonment ("DPA") of all fields over the contract's duration includes Development and Production Periods. The Development Period comprises the Pre-Development Phase of up to 2 years from the effective date and the Development Phase of up to 2 years from the effective date. The Production Period will be up to 10 years (depending on the assets); the Maintenance Period will be up to 2 years depending on the assets.[173]

The bare minimum work commitments expected of contractors during the Pre-Development Phase, which includes resource assessment and/or maturation studies, as well as drilling of one appraisal well, and the Development Phase, which provides for achieving First Commercial Production (FCP) in accordance with the approved Field Development and Abandonment Plan (FDAP).

In terms of reporting, the contractors are expected to submit an Annual Work Plan, FDAP filing, which must be completed within two years after the PSC signing. In addition, the cess treatment must be undertaken on a unit of production ("UOP") basis with a factor of up to 1.5.

Furthermore, with regard to the mechanism for cost recovery of the SFA fiscal model, it should be highlighted that the SFA fiscal model must be simple and straightforward in order to ensure the successful monetization of small fields. The ability to reduce operating expenses while simultaneously boosting profit margins allows the operator to reduce costs while growing profits.[174]

In this regard, the entitlement would be divided into three categories: the government's portion, PETRONAS' portion, and the contractor's portion. For example, the following percentages might be used: 10% Cash Payment to the government; a fixed Y% of Gross Production to Petronas (Petronas Share); and X% of Gross Production to Contractor (Contractor Share).

A minimum of Y per cent will be established, against which bidders may make their incremental offers. The contractors are entitled to their shares after deduction of the 10% cash payment to the government and Y% of Gross

172. *Id.*
173. *Id.*
174. *Id.*

Production to Petronas. Throughout the contract duration, the proportion of Y does not fluctuate in any way.

Amounts such as capital expenditures (CAPEX), operating expenses (OPEX), and abandonment costs are included in the computation of X per cent of gross production. Once the government receives a 10 percent cash contribution, the X per cent is 90 percent less than the Y percent (Petronas Share). In addition, abandonment cess shall be paid in full by UOP by the time the field reaches its midpoint in terms of production.[175]

Other PSC payments, such as the supplemental charge, research cess, training contribution, and educational fund, are not required to be included in this calculation. According to Malaysian law, contractors are responsible for paying any taxes they are liable to pay, regardless of whether the taxes are charged by the federal, state, municipal governments, or local governments and municipalities.[176]

3. Shallow Water Enhanced Profitability Terms (EPT)

The Shallow Water Enhanced Profitability Terms (EPT) Production Sharing Contract (PSC) is a clear contract that represents a progressive and innovative method to adjust to the current market conditions. Its purpose is to use the hydrocarbon resources discovered in Malaysia's shallow-water offshore oil and gas blocks. The EPT would take the place of the 1997 Standard Revenue Over Cost (R/C) PSC Terms in the case of possible shallow-water exploration contracts.[177]

To rekindle interest in and investment in Malaysia's hydrocarbon reserves, the new, improved shallow water EPT will provide a number of benefits to contractors. The new enhanced shallow water EPT will be implemented in phases. New fiscal interactions, reflected in leaner, more specific, and more attractive words, are encouraged by the EPT in order to balance the possibilities in shallow-water blocks.[178]

The structure is intended to offer a clearer perspective of the overall depiction of the hydrocarbon sharing arrangement than the traditional representation. The examination of PSC claims would take less time,

175. *Id.*
176. *Id.*
177. *The Shallow Water Enhanced Profitability Terms (EPT) PSC*, PETRONAS, https://www.petronas.com/mpm/investment-opportunities/fiscal-terms/ (last accessed Apr. 20, 2023).
178. *Id.*

decreasing the requirement for a more significant administrative function within the PSC.[179]

Contractors will benefit from a more robust fiscal framework and pricing to decrease risk and volatility in resource production and expansion and a more equitable division of profits on the upside scenarios.[180]

Some of the essential elements of the EPT include a 10 percent cash payment to the government, a single cost bank for oil and gas, a fixed cost recovery maximum of 70 percent, and a linear profit-sharing system, among others (90 percent -70 percent). In addition, it eliminates the Supplementary Payment (SP) and Threshold Volume (THV) provisions in order to ensure a fair distribution of upside benefits among all participants.[181]

Regarding the Mechanism for Cost Recovery for the EPT Fiscal Model, the PSC makes management more accessible. The EPT bases cost recovery and benefit share on a typical oil and gas pool rather than independent oil and gas accounts.[182]

Regarding cash payments, the federal and state governments each receive a share of the overall revenue equal to 10 percent of the total income.[183]

To ensure that costs are recovered as quickly as possible and that a more substantial recovery pool is available throughout the PSC's lifespan, the cost recovery limit has been established at 70% of gross production.[184]

For the purpose of determining profit-sharing, it is crucial to remember that, once cash payment and cost recovery have been completed, the residual output is regarded as a benefit, which is divided between PETRONAS and the contractor through the use of a self-adjusted profit-sharing plan. For contractors, the profitability index (PI) is used to determine their profit share, with an overall proportion of 90 per cent for PIs up to 1.50 and a minimum share of 30 per cent for PIs equal to or more than 2.50.[185]

The PI is computed by dividing the net contractor's right, which includes cost recovery and benefit-sharing, by the entire recoverable cost from the beginning of the contract period. In the case of profitability indices up to 1.50, the cash flow front loading represented by 70 per cent maximum cost recovery and 90 per cent contractor profit sharing will shorten the after-tax discounted payback term. Furthermore, the incremental modification

179. *Id.*
180. *Id.*
181. *Id.*
182. *Id.*
183. *Id.*
184. *Id.*.
185. *Id.*

provides an excellent hedge for the contractor to manage risk in the case of unfavorable circumstances, such as lower actual price and volume disadvantages, as opposed to the traditional modification.[186]

As previously stated, the THV and SP clauses do not apply in the EPT context. Due to the fact that the EPT is designed to use a single benefit matching tool to assess profit share between PETRONAS and the contractor, it allows for an equal sharing of upside incentives, encourages reinvestment within the commodity, and promotes numerous sector improvements throughout the PSC's life span.[187]

3.6. Kazakhstan

a) Brief explanation about the evolution of PSCs and cost recovery in your jurisdiction

PSCs play the role of a dominant minority in the oil industry of the Republic of Kazakhstan. There are only 10 active PSCs in force in 2021 in respect of oilfields currently in force.[188] The most significant in terms of production and revenue are Kashagan, Karachaganak and Dunga.[189] Of the remaining PSCs, Pearls is in the process of being terminated,[190] Temir and Mynteke South are due to expire by 2025 and Kurmangazy is not presently in production.[191] The remaining production is governed by subsoil agreements under tax & royalty terms,[192] taxed under current law or

186. *Id.*

187. *Id.*

188. Summary details up-to-date as of 2017 can be found in the Extractive Industries Transparency Index report for Kazakhstan available at https://eiti.org/sites/default/files/documents/english_2017_eiti_report_kazakhstan.pdf accessed 25th May 2021. On page 69 of that report, 10 PSCs are listed; in the author's opinion, Tengiz is wrongly included in that list because it is not subject to production sharing and is subject to a tax & royalty regime. The Dunga PSC should also be included.

189. *Projects*, PSA, https://www.psa.kz/en/proekty/ (last accessed Apr. 20, 2023). Kashagan & Karachaganak PSCs signed 1997, Dunga PSC signed 1994.

190. *Royal Dutch Shell Backs Out of Offshore Projects in Kazakhstan*, CASPIAN NEWS, https://caspiannews.com/news-detail/royal-dutch-shell-backs-out-of-offshore-projects-in-kazakhstan-2019-10-23-2/ (last accessed Apr. 20, 2023).

191. *See Kurmangazy*, KAZMUNAYTENIZ, https://www.kazmunayteniz.kz/en/projects/kurmangazy/ (last accessed Apr. 20, 2023).

192. *On Subsoil and Subsoil Use*, MINISTRY OF JUSTICE OF THE REPUBLIC OF KAZAKHSTAN INSTITUTE OF LEGISLATION AND LEGAL INFORMATION, https://adilet.zan.kz/eng/docs/K1700000125. The State's database of petroleum licences lists 245 hydrocarbon exploration and/or production licenses as at 1 January, 2018 (*see* http://info.geology.gov.kz/images/stories/spravochnik/ubs01.01.18.pdf accessed 25 May, 2021). Of these licences, all but 42 were awarded prior to 2011.

stabilized to separately agreed terms of taxation. PSCs are not numerically dominant but are disproportionately significant in the level of production and revenue delivered to the State and investors.[193] The first part of this paper explains the conundrum.

The oil industry of the Republic of Kazakhstan has a long history, going back at least as far as the post-war years, when the Soviet Union prioritised oil exploration in the Volga basin to offset the loss of production from Azerbaijan caused by the deliberate plugging of producing wells to prevent them falling into enemy hands during Operation Barbarossa.[194] Foreign investment in the oil industry was possible prior to the fall of the Soviet Union through joint venture participation, but accelerated rapidly thereafter. The circumstances in which the first few Kazakh PSCs were signed have been discussed by several journalists and legal authors.[195] In brief, the three main PSCs still in force and in production today, Karachaganak, Kashagan and Dunga, were agreed through bilateral negotiations between the relevant foreign consortia and working committees representing the State in the course of the period 1987–1997. The combined revenue to the Republic of Kazakhstan from the 9 PSCs reported by EITI for 2017 as reported by Extractive Industries Transparency Initiative was Tenge 409 billion (equivalent to USD 0.95 billion dollars at May 2021 exchange rates), comprising 12.5 % of reported revenue from all other petroleum ventures in that period.[196] However, the leading oil and gas project in Kazakhstan remains Tengiz, which is governed by a bespoke subsoil agreement on "tax & royalty" terms. The Tengiz agreement was signed in 1993. Its contribution to the Kazakhstan State revenue in 2017 was 1.762 billion Tenge

193. In the first half of 2018, Tengiz, Karachaganak and Kashagan together produced more than 27 million metric tonnes of condensate. The next top seven producing companies in Kazakhstan contributed a further 11.8 million tonnes. The Republic produced 90 million metric tonnes of crude and condensate in the full year 2018. *The National Energy Report 2019*, KAZENERGY, https://www.kazenergy.com/upload/document/energy-report/NationalReport18_ru.pdf (2019).

194. Steve Levine, *The Oil and the Glory: The Pursuit of Empire and Fortune on the Caspian Sea* 50 (2007).

195. *Id.*; O.I. Chentsova, *Granting the Right of Subsoil Use on Legislation of the Republic of Kazakhstan* (1996), https://online.zakon.kz/Lawyer (last accessed Apr. 20, 2023); Z.S. Yelyubayev, *Role of Investment Law in Regulating Relations in the Sphere of Subsoil Use in the Republic of Kazakhstan*, OGEL (March 2010).

196. For this purpose, the information provided by the EIT I report for 2017 page 69 was used, removing the data for Tengiz as it is not a PSC field. The overall income from the oil sector to the state budget and national fund was derived from the report at page 131 (a gross figure of Tenge 329 8 billion).

(approximately 4.2 billion USD at May 2021 exchange rates), equivalent to 53% of reported revenue from all other petroleum ventures.[197]

Since the ground-breaking days of the 1990s, PSCs became regularized through the enactment of the "Production Sharing Agreements for Offshore Oil Operations" Law of 2005, which permitted the award of PSCs in the Caspian and Aral Sea areas. It did not contemplate awarding PSCs for onshore projects. At least in legislative terms, the State allowed only for the award of "tax and royalty" agreements for onshore projects, under the terms of a sequence of subsoil laws enacted in 1996 & 2010, culminating in the Subsoil Code of 2018. The law that brought the 2008 Tax Code into effect revoked the law on "Production Sharing Agreements for Offshore Oil Operations."[198] Only two offshore PSCs awarded while the law was in force are in effect today—Pearls and Kurmangazy. The 2018 Subsoil Code also made no provision for the award of any new production sharing agreement by the Republic of Kazakhstan.

Accordingly, PSCs have been in and out of fashion in the Republic of Kazakhstan. The popularity of PSCs in the initial period, when Karachaganak, Kashagan, and Dunga were awarded, is explained by the State's lack of capital and resources adequate to develop significant resources at a time of lower oil prices. The oil companies desire to lock in advantageous terms while the Republic was institutionally and legislatively developing, adapting as rapidly as possible to independence and market economics.[199] Between the period 2004–2010, the State became increasingly disillusioned with the terms applicable to the Kashagan project, which was dogged with cost overruns and delays in production start-up. This is why it restricted PSCs to offshore exploration and production, before ceasing to offer such terms altogether. The State last awarded a PSC in 2005 and there is no legislative basis on which to issue a PSC at present. Under the 2018 Subsoil Code, the State has approved a standard subsoil agreement on "tax & royalty terms." Under such terms, the subsoil user is subject to general corporate income tax and mineral extraction tax, with the option of switching to Alternative

197. Kazakhstan 2017 EITI Report, EITI, https://eiti.org/documents/kazakhstan-2017-eiti-report (last accessed Apr. 20, 2023). Further, the report indicates that the state's share of profit oil from active PSC is represented 1.9% of all income from the oil sector in that year.

198. *On Taxes and Other Obligatory Payments into the Budget (Tax Code)*, Ministry of Justice of the Republic of Kazakhstan Institute of Legislation and Legal Information, (Dec. 10, 2008), available at https://adilet.zan.kz/eng/docs/K080000099_ (last accessed Apr. 20, 2023).

199. *See* Jenik Radon, *Kazakhstan's PSA Challenge: Sanctity of Contracts vs. Stabilization*, OGEL (March 2010).

Subsoil User Tax (ASUT) for more complicated reservoirs.[200] Such agreements do not provide recovery of costs from produced petroleum. Neither does the 2018 Subsoil Code provide terms on which the State might award a risk service contract (even though the 2015 Law on Petroleum did do so).[201]

b) Brief explanation about the challenges and concerns with PSCs and cost recovery in your jurisdiction

From the above analysis, it is safe to draw the conclusion that the recovery of the contractor's costs through the allocation of petroleum is a mechanism limited to a small number of projects in production, which are subject to PSCs—Karachaganak, Kashagan, and Dunga being the most significant. These three projects are the responsibility of a specific division within the Ministry of Energy, PSA LLP, whose staff is responsible for the Ministry's engagement with the projects, including attendance at management committee meetings, approval of procurement contracts, approval of work programs & budgets, and significant support for the projects' efforts in local content development.[202] Kashagan is rumored to have cost 50 billion USD. It began production in 2016 and is delivering at a rate of just under 400,000 barrels per day; it therefore carries an enormous cost recovery burden. Karachaganak, by contrast, is less expensive, but is presently executing a series of expansion and plateau extension projects, the costs of which may exceed operating revenues for some time. In 2019, the Dunga Operator Total announced approval of Phase III development, potentially adding 10% to production levels through additional production wells and processing capacity, in the extension of the Dunga PSA from 2024 through to 2039.[203] Recovery of the investors' costs, be the capital or operating expenditures, must be front and center in the minds of the contractors.

Therefore, it is no surprise that many of the costs which the investors seek to recover through the allocation of cost petroleum are subject to challenges

200. *Kazakhstan Oil and Gas Tax Guide 2021*, ERNST & YOUNG, https://assets.ey.com/content/dam/ey-sites/ey-com/ru_kz/topics/oil-and-gas/ey-kazakhstan-oil-and-gas-tax-guide-2021.pdf (last accessed Apr. 20, 2023).

201. Law "on Petroleum" 1995 Article 25.1 (3).

202. PSA, https://www.psa.kz/en/ (summary project status summaries) (last accessed May 9, 2023).

203. *Kazakhstan: Total Launches Phase 3 of the Dunga Field,* TotalEnergies (last accessed May 18, 2021), https://www.total.com/media/news/press-releases/kazakhstan-total-launches-phase-3-dunga-field.

by the State. This was confirmed by the national oil company, Kazmunaigaz's 2020 Annual Report, which comments as follows:

> As of December 31, 2020, the Group's share in the total disputed amounts of costs is 1,078 million US dollars (equivalent to 453,641 million tenge as at reporting date) (2019: 1,052 million US dollars, equivalent to 402,474 million tenge as at reporting date), including its share in the joint venture. The Group and its partners under the production sharing agreements are in negotiation with the Government with respect to the recoverability of these costs.[204]

Given that KazMunayGas's participating interest in the Kashagan project is 16.8%, 10% in Karachaganak, and no participation in Dunga, it is clear that the gross costs in dispute with the State with respect to the Kashagan and Karachaganak projects must reach close to $10 billion overall.

None of the Kashagan, Karachaganak, or Dunga PSCs is publicly available, and no model PSC has been formally published by the State either. The following comments therefore are necessarily high-level and theoretical, based on the authors' personal experience of managing cost recovery disputes, whilst protecting the confidentiality of those agreements.

The State's control of costs under PSCs can be front-ended and back-ended. Through the project management committees, the State's representatives approve each year's work program and budget, while also involved in approval of significant procurement contracts. Nevertheless, the State also conducts cost recovery audits, challenging any expenditure which is not within the scope of the relevant program and budget, or has been spent under a contract which should have been approved by the relevant state body and was not. This two-step control of costs brings significant bureaucratic burdens for the project which can be counterproductive. Firstly, it creates additional tension in negotiation of program and budget approvals, on which the project depends for cost recovery. Any delay in such approval may cause the project operator to defer the relevant operations, if possible. Secondly, there is tension between the parties' expectations of how a program and budget function in the governance of the project. The contractor is likely to treat it as a business plan and cost estimate in the same way it functions under the corresponding joint operating agreement. The State, however, may treat it more like a contractual work, which the EPC contractor must follow to the

204. *Notes To The Consolidated Financial Statements For The Year Ended December 31, 2020*, KazMunayGas (last visited May 18, 2021), https://ar2020.kmg.kz/.

tee, or they would be in breach of contract for failing to comply. The project operator has a margin of flexibility to deliver the approved operations, within the relevant period and budget. The State may treat the information provided to justify the program and budget as contractually binding promises as to how the work will be performed and delivered. Accordingly, any deviation from such "promises" can be used to justify the State in excepting the associated costs. Thirdly, the time delay between the relevant approvals and the following audit can be significant, leading to dispute as to what was approved and on whose authority. In a sense, the project operator must satisfy the State's technical and geological staff before the work is carried out, and then the State financial audit staff afterwards.

Normally the PSCs will provide that the state must conduct its cost recovery audit within one or two years of the end of the relevant financial year and cannot reopen an audit unless there is evidence of fraud or manifest error in the information provided. Unlike a statutory audit of financial statements, which routinely operates on a sample basis, the auditors will likely require to see 100% of the documentation supporting the costs claimed. In part, this is to avoid any allegations that the auditors have shown favor or concession to the contractor, which may attract allegations of bribery and corruption. Exactly how each item of expenditure should be evidenced is also contentious. There is no statement of international good practice for cost recovery auditing as it exists for statutory audits. Common issues that cause conflict include the availability of signed and apostilled documentation (which may be commonplace in Kazakh business, but unheard of in OECD countries), disputes around the remuneration of expatriate employees (usually considerably higher than the remuneration of local staff), and questions about the parent company's overhead charge of management and administrative support provided by the contractor's overseas affiliates.

The result is an extremely painstaking and lengthy process. There is no substitute for establishing a working relationship between the state's and the contractor's cost recovery teams. These leads to the agreement of written procedures for the collection and preservation of cost recovery evidence, in order to minimize disputes. This is important because cost recovery disputes are extremely expensive and time-consuming. More importantly, cost recovery disputes can cause the contractor to defer investment if they believe that its return on investment has to take into account a proportion of its costs that will never be recovered.

A very significant issue which arises in the context of cost recovery disputes is taxation. Simply put, the State tax authorities may take the view that cost recovery is subject to some or all of the rules applicable to tax assessments because the State's share of petroleum profit is, to a significant extent, defined by the level of cost petroleum allocated to the contractor. Furthermore, it is often the case that the PSC will set out a list of taxes payable by the contractor (usually on stabilized terms), including the "payment" of the State's share of profit oil as tax. On the other hand, there is almost no bespoke legislation applicable to the State's share of profit oil, it arises under and in accordance with the terms of the PSC.[205] If the PSC has the force of law (and for example the tax instructions applicable to the Karachaganak project have been brought into the State legislation) then a conflict of law may also arise between the tax legislation and the PSC.[206] That conflict gets complicated where the PSC is stabilized under two different regimes; it may be stabilized for tax against the tax law applicable at the time it was signed, and stabilized against other legislative changes in a more generic manner. For reasons discussed above, the chances are that the legislation in force at the time the PSC was signed did not address questions of profit oil allocation, still less cost recovery.

More significantly, it is hard to accept that the State's share of profit oil can constitute a tax payable by the contractor if the contractor doesn't own the oil until after the State has allocated its share to it, and the contractor share is allocated to the contractor. Should a contractor pay taxes by allocating to the State petroleum, which the State already owns? The Republic of Kazakhstan has been consistent on the question of when and how the contractor is allocated title to the petroleum it captures. Their constitution states that the land and its subsoil belong to the State.[207] Consistently, the 1995 law "on Petroleum" elaborated on this principle by stating that the owner of petroleum lifted to the surface should be stated by the relevant subsoil contract, and the right to dispose such petroleum shall vest in the owner identified in the contract unless the contract provides otherwise.[208] This logic has been followed through in the law 2010 "on the Subsoil and Subsoil Use" and the 2018 Subsoil Code.[209] Accordingly, it can be argued

205. One exception to this is the December 25, 2014, Instruction of the Ministry of Finance Report No. 587 bringing into effect rules on the calculation of the amounts payable and time for payment of the Republic's share under production sharing agreements provided in kind.

206. Government Decree of 13 December, 2011 number 1525 "on certain questions with respect to the Karachaganak Project". Available at https://online.zakon.kz/Lawyer, last visited 18th of May 2021.

207. Const. of the Republic of Kazakhstan art. 6.3.

208. Law of the Republic of Kazakhstan, 1995 (art. 3).

209. Law of the Republic of Kazakhstan, 2010 (art. 10); Code of the Republic of Kazakhstan, 2018 (art. 11, 15).

that the contractor does actually take title to petroleum produced by its project and then transfers title back to the State when cost petroleum and profit petroleum are allocated in accordance with the PSC and any lifting agreement that may also apply.

The consequences of treating cost recovery of state profit oil as a tax can be severe. It creates significant uncertainty for the State representatives as to whether they are authorized or not to approve costs for recovery by the relevant tax authorities, and it is unprecedented for tax officials to approve cost before it is incurred. Inevitably, the State tax authorities are likely to apply rules applicable to the deductibility of costs for corporate income tax purposes because they are not comfortable justifying their decision on the terms of the PSC, even if it formally has the force of law. The contractor, by contrast, is frustrated by the lack of certainty with respect to the cost recovery audit process; it expects the State oil and gas regulator to follow the rules set out in the relevant PSC, its accounting procedure, or other agreed procedures with respect to cost recovery documentation and audit. But many times the tax authorities consider themselves entitled to conduct a further audit on a timetable prescribed by the tax legislation, often years after the State oil and gas regulator has conducted its audit. Furthermore, the tax authorities may expect to see documentation with respect to cost which the oil and gas regulator (or the terms of the PSC) did not require the contractor to keep. That point is especially controversial if the terms of the PSC provide that a cost recovery exception cannot be raised with respect to expenditure which has already been audited and approved for cost recovery by the oil and gas regulator, in the absence of fraud or material non-disclosure.

In detail, a conflict can arise between the tax authorities and the contractor with respect to the applicability of the PSC's terms and modern tax legislation. Kazakhstan legislation routinely grandfathers' contracts by stating that fresh legislation will not affect the applicability of existing contract terms but will apply to the extent that the relevant contract does not address matters addressed by the new legislation. Inevitably, the PSC's definitions of what is and is not cost recoverable expenditure will be less detailed and less refined than the tax legislation governing deductible costs for corporate income tax purposes. This justifies the tax authorities in deploying tax legislation to clarify ambiguities in the PSC on cost recovery in a manner which the contractor will treat as irrelevant and conflicting with the implicit, if not express terms of the PSC.

c) Brief explanation about solutions adopted or at least considered to solve the said challenges and concerns.

Even though there may be as much as $10 billion of outstanding cost recovery exceptions to be agreed between the Republic and the Kashagan and Karachaganak projects, fresh investment in those projects proceeds. To some extent, the several disputes that dogged those projects in the last two decades have reset the State investor relationship and resolved some cost recovery issues along the way. Some progress towards eliminating the scope for cost recovery disputes can be made by agreeing ever more detailed procedures for the documentation, approval, and audit of project costs, giving the State representatives more comfort when approving those costs for recovery.

However, there is a risk of history repeating itself. Once the project has reached the point of turnover from production, paid back development costs and exceeds operational expenditure, petroleum will be allocated to cost petroleum. The relevant costs recovered from cost petroleum proceeds before the relevant costs are audited, with the prospect of subsequent adjustments when the audit results are agreed or resolved at a later date. This leaves the contractor in a comfortable position, until the position switches; as soon as it invests in enhanced oil recovery or plateau extension projects, its capital expenditure may once more outrun the proceeds of sale of ongoing production, with the result that certain costs are carried forward until they are audited. The potential, therefore, arises for the State to consider that the project has reached payback when the contractor considers it still has capital expenditure to recover; in consequence, the State and contractor may believe that the allocation algorithms for petroleum production may have starkly different results because the State and contractor are far apart in their respective assessments of how much cost petroleum the contractor is entitled still to lift. This will not only be a matter for protracted audit and legal debate but will radically affect who owns which proportion of oil cargoes as they are lifted and loaded, bringing that long-term dispute very much into real-time focus.

3.7. Guyana

a) Brief explanation about the evolution of PSCs and cost recovery in your jurisdiction

Guyana is a relatively new emerging frontier oil and gas producer, with the first announcement of a major discovery of oil being made in 2015.[210] Petroleum exploration is important to Guyana because if properly managed, oil revenues have the potential to transform the country's economy and can have a sustainable impact on the country's development. Guyana is one of the poorest countries in South America.[211] The country has a population of approximately 790,000,[212] and thirty-five percent of the Guyanese population live below the poverty line.[213] However, since 2020, the country is currently experiencing one of the world's fastest economic growth driven by ExxonMobil's discovery of oil.[214] Guyana is projecting that by 2025, the GDP will go up by 300% to 1,000% and with the oil discoveries, it could catapult to the top of the continent's rich list and beyond.[215] It is estimated that ExxonMobil has discovered approximately 10 billion barrels of oil equivalent of recoverable oil in the offshore areas.[216]

---

210. Clifford Krauss, *With a Major Oil Discovery, Guyana is Poised to Become a Top Producer*, The New York Times (Jan. 13, 2017), https://www.nytimes.com/2017/01/13/business/energy-environment/major-oil-find-guyana-exxon-mobile-hess.html.

211. David Papannah, *Guyana, One of the Poorest Countries in South America, Defers its Dreams of Oil Riches to Battle COVID 19*, Caribbean Investigative Journalism Network (Sept. 1, 2020), https://www.cijn.org/guyana-one-of-the-poorest-countries-in-south-america-defers-its-dreams-of-oil-riches-to-battle-covid-19/.

212. *See Guyana Population,* Worldometer (Apr. 8, 2023), https://www.worldometers.info/world-population/guyana-population/.

213. *See Fighting to End Poverty in Guyana*, Food for the Poor (last visited Apr. 08, 2023), https://www.foodforthepoor.org/our-work/where-we-serve/guyana/.

214. *See Towards a Transparent and Effective Management of Guyana's Oil and Gas Sector*, The World Bank (Apr. 2, 2019), https://www.worldbank.org/en/news/press-release/2019/04/02/towards-a-transparent-and-effective-management-of-guyanas-oil-and-gas-sector; *see generally Guyana*, International Monetary Fund (last visited Apr. 8, 2023), https://www.imf.org/en/countries/guy?selectedfilters=Article%20IV%20Staff%20Reports#whatsnew.

215. Simon Maybin, *Will Guyana soon be the richest country in the world?*, BBC News (May 9, 2019), https://www.bbc.com/news/world-latin-america-48185246.

216. Keith Myers, *Latest Guyana discovery opens the way to a new 10 billion barrel oil province and transformation for one of South America's smallest countries*, Westwood Global Energy Group (Sept. 5, 2018), https://www.westwoodenergy.com/news/westwood-insight/latest-guyana-discovery-opens-the-way/.

Guyana's fiscal system and the general legal framework governing the oil and gas sector is outdated and currently undergoing legislative reform.[217] It is important that the State of Guyana puts in place the legal framework to properly regulate and manage this oil and gas sector. Under Guyana's laws, petroleum is vested in the State and the State has the exclusive right of searching for and getting such petroleum.[218] The 1986 Petroleum (Exploration and Production) Act and 1986 Petroleum (Exploration and Production) Regulations (the "1986 Petroleum Regulations") govern and regulate exploration and exploitation of petroleum in Guyana.[219] The Act envisages that a production sharing contract not inconsistent with the Act, will document any such settled terms and conditions to be included in licenses granted under the Act. The minister responsible for petroleum, the Minister of Natural Resources, is authorized by the Act to conclude such agreements. The Act also empowers the Minister of Natural Resources to grant a petroleum prospecting license and a petroleum production license for the prospecting of petroleum and matters connected therewith. A petroleum prospecting license usually lasts for ten years, and the Act sets out the conditions concerning the duration, renewal, cancellation, and other powers relevant to petroleum operations. The terms and conditions of the production sharing contracts between the Government of Guyana and oil companies are usually established through negotiations.

There is no comprehensive model production sharing agreement available by the Government of Guyana for prospective investors. Rather, the Government of Guyana's Geology and Mines Commission website shares an outline which they refer to as "Articles in the Guyana's Petroleum Agreement."[220] These articles are very vague and leave lots of room for the relevant authority to exercise this discretion. Regarding Cost Recovery and Production Sharing, the articles provide as follows:

---

217. *See US, local law firms hired to revamp, develop legislation for oil sector*, News Room (Feb. 11, 2020) https://newsroom.gy/2020/02/11/us-local-law-firms-hired-to-revamp-develop-legislation-for-oil-sector/.

218. *See* Petroleum (Exploration and Production) Act, 1986, https://parliament.gov.gy/documents/acts/8170-act_no._3_of_1986_petroleum_(exploration_and_production)_act_1986.pdf.

219. The Petroleum Regulations (Legal notice 5 of 1986) made pursuant to section 70 of the Petroleum (Exploration and Production) Act, (no. 3 of 1986), Cap. 65:10, Laws of Guyana.

220. *Articles in Guyana's Petroleum Agreement*, Guyana Geology and Mines Commission (Jan. 29, 2019), https://www.ggmc.gov.gy/services/all/articles-guyanas-petroleum-agreement.

> Where production sharing is in the form of association chosen, the details of precisely how production from the license area is allocated in this Article "Cost Oil" and "Profit Oil" are clearly detailed to avoid ambiguity. The method of cost recovery and crude oil pricing is outlined. These provisions are negotiated.[221]

This means that there is no predetermined non-negotiable figure nor percentage which the government has in mind.

The 2016 Guyana-ExxonMobil PSC is the first signed PSC which was released for the public to view. The PSC covers the Stabroek Block, which extended to 6.6 million acres or 26,800 square kilometers. ExxonMobil's affiliate Esso Exploration and Production Guyana Limited is the operator and holds 45 percent interest in the Stabroek Block. Hess Guyana Exploration Ltd. holds 30 percent interest and CNOOC Petroleum Guyana Limited, a wholly owned subsidiary of CNOOC Limited, holds 25 percent interest.[222] The 2016 Guyana-ExxonMobil PSC was negotiated between the Government of Guyana and the oil companies. The government did not conduct any competitive bidding before they entered into this agreement with ExxonMobil and its partners. The government explained that one of the reasons for this decision was because the petroleum sector was not developed at the time and felt it was appropriate to have a one-off negotiation for the Guyana-ExxonMobil PSC.

The PSC included very generous terms regarding royalty, cost recovery, taxation, and profit sharing for the international oil companies. Arguably, the generous terms were offered to attract investment. Under Article 15.5 of the Guyana-ExxonMobil PSC,[223] the contractor agrees to pay the Government a royalty of 2 percent (increased from 1 percent under an earlier 1999 Agreement between the international oil companies and the government at that time). Article 11 on cost recovery and production sharing provides that Guyana will receive 50 percent of the share of profits after deducting up to a maximum of 75 percent of recoverable costs from monthly revenues. This means that on the monthly earnings from the production of oil, the contractor is allowed to recover his expenses from 75 percent of the total revenues. The

221. *Id.*

222. *Guyana Project Overview*, Exxon Mobil (last visited Apr. 8, 2023), https://corporate.exxonmobil.com/Locations/Guyana/Guyana-project-overview.

223. 2016 Petroleum Agreement between the Government of Guyana and Esso Exploration and Production Guyana Limited with CNOOC Nexen Petroleum Guyana Limited and Hess Guyana Exploration Limited, *known as* 2016 Guyana-ExxonMobil PSC, https://dpi.gov.gy/wp-content/uploads/2019/07/Petroleum-Agreement-Esso-Cnooc-Hess-Guyana-Ltd..pdf.

Government of Guyana and the contractor will evenly split that the remaining 25 percent. This means that the Government of Guyana is ultimately guaranteed a minimum of 12.5 percent of the production. When the 2 percent royalty is added, the Government of Guyana gets 14.5 percent of the total production.

"Recoverable Contract Costs" are defined under Article 11.2 of the Agreement to mean such costs as the contractor is permitted to recover from the date they have been incurred.[224] The Agreement elaborates on exploration, development, operating, and other costs or expenditures which can be recovered under Annex C. Drilling costs, if the wells are dry, are recoverable. Insurance costs incurred by the company are also recoverable. Legal expenses of litigation and related services in defending or prosecuting lawsuits involving the contract area or any third-party claim arising out of activities under the agreement are recoverable.

The 2016 Guyana-ExxonMobil PSC also provided that the pre-contract costs incurred by the Contractor with respect to the petroleum operations carried out under the 1999 Petroleum Agreement were recoverable. Annex C, section 3(1) (k) of the 2016 Guyana-ExxonMobil PSC provides that the sum of four hundred and sixty million, two hundred and thirty-seven thousand and nine hundred and eighteen United States dollars ($460,237,918 USD) is recoverable as pre-contract costs including contract costs, exploration costs, operating costs, service costs, and general administrative costs under the 1999 Petroleum Agreement. This means that ExxonMobil has billed the Government of Guyana to recover the cost of work done during the exploratory phase of the operations.

The Agreement also provides that any excess recoverable costs are to be carried over to the following month. The Agreement further provides that the Government of Guyana will pay the taxes of the Contractor out of the Government's share, and this will be considered income of the Contractor. This means that the government will give a tax receipt to ExxonMobil and their partners in their names stating that they have paid their taxes. When the prospects of finding oil in commercial quantities in Guyana was risky, generous terms were used to attract investors. However, these can now be limited, and the Government has stated its intention to develop a new fiscal framework and new petroleum legislation.

224. *Id.*

The 2016 Guyana-ExxonMobil PSC has received several criticisms from local and international media.[225] The International Monetary Fund (IMF) and several other international bodies have advised the government to put together a model PSC with the minimum fiscal terms or package to be accepted for future contracts.

b) Brief explanation about the challenges and concerns with PSCs and cost recovery in your jurisdiction

The PSC in Guyana is disadvantageous to the Government of Guyana because it has the potential for "gold-plating." Gold-plating refers to attempts by companies to inflate costs through overspending on the oil and gas projects. Companies can be found gold-plating when the fiscal regime gives them an incentive to spend more on capital investment and claim a greater share of project revenues. One of the solutions to the gold-plating problem is for the host government to carefully monitor the expenditure of the international oil companies. Also, international oil companies have a greater incentive to gold-plate if they are procuring goods and services from affiliates or subsidiary companies. This can be monitored through a number of mechanisms. The 2016 Guyana-ExxonMobil PSC requires government approval of annual work programs and budgets, but there is uncertainty whether the government is closely checking for these occurrences.[226] Close monitoring and auditing of expenses are essential to a successful cost recovery provision under any PSC. The lack of proper audit provisions under the 2016 Guyana-ExxonMobil PSC means that it is difficult for the government to assess the reasonableness of expenditures in an efficient manner.

Another important issue related to gold-plating is the two-year deadline the government has accepted under the PSA for auditing the international oil companies' expenses. In 2021, the Government of Guyana failed to conduct cost audits within the two-year deadline prescribed in the 2016 Guyana-ExxonMobil PSC. As a result, Guyana had no choice but to allow ExxonMobil's subsidiary, Esso Exploration and Production Guyana Limited

225. *See ExxonMobil contract illegal; irretrievably flawed and is either the result of grand corruption or grand incompetence*, Stabroek News (June 6, 2019), https://www.stabroeknews.com/2019/06/06/news/guyana/exxonmobil-contract-illegal-irretrievably-flawed-and-is-either-the-result-of-grand-corruption-or-grand-incompetence/; *see also Oil agreement generous to Exxon – IMF team-loopholes for abuse seen*, Stabroek News (Dec. 24, 2017), https://www.stabroeknews.com/2017/12/24/news/guyana/oil-agreement-generous-to-exxon-imf-team/.

226. 2016 Guyana-ExxonMobil PSC, *supra* note 225.

(EEPGL), to recover all stated costs for its Liza Phase One and Two Projects. Both initiatives totaled approximately $9.5 Billion USD.[227] Additionally, the oil company was also able to recover the costs of approximately $460 Million USD, which the oil company claimed was expended prior to signing the 2016 Production Sharing Contract. This is another set of expenditure which the oil company will also be able to recover, without any challenges from the government of Guyana. The oil company said this money was spent on the exploratory work that was needed for the massive 2015 Liza discovery. In response to the failure of the government to audit the expenses under the PSC, the Vice President of Guyana, Mr. Bharrat Jagdeo, said that the absence of strong local groups to do the audits is what stymied the process.[228] It appears that Guyana currently lacks the necessary legal and regulatory tools, expertise, or information to properly audit the international oil companies' expenses. Furthermore, conflicting incentives and political pressures may complicate their mandate to properly monitor and audit this industry to maximize revenue collection.

International transparency bodies, including Oxfam America, have strongly contended that the two-year deadline the government has accepted under the PSC, along with the fact that it can only do one audit per year on Exxon, is not sufficient.[229] They have stressed that the timeline should be extended. It's to be noted that these deadlines differ from one country to the next. In Ghana and Kenya for example, the authorities retain the right to complete auditing companies within seven years. In Peru, the time limit for audits is a minimum of four years. Even in the USA, Oxfam highlighted that audits are allowed to be completed within a minimum of three years. Oxfam cautioned, however, that even a three-year deadline is not advisable for developing countries such as Guyana given the limited financial and human resources that are likely to delay the audit process. Further, Oxfam warned that Guyana needs to take the auditing timeline for these costs as a matter of grave concern as it could cost the nation billions more.

The lack of ring-fencing provisions in the 2016 Guyana-ExxonMobil PSC is another issue which impacts cost recovery under the agreement. Ring fencing provisions prevent ExxonMobil from deducting expenses associated

227. *Savings from audit of Exxon's US$9.5B bill could have paid every citizen's income tax for 56 yrs – Forde,* Kaieteur News (Nov. 9, 2021), https://www.kaieteurnewsonline.com/2021/11/09/savings-from-audit-of-exxons-us10b-bill-could-have-paid-every-citizens-income-tax-for-56-yrs-forde/.

228. *Id*.

229. *Examining the Crude Details - Government Audits of Oil & Gas Project Costs to Maximize Revenue Collection*, Oxfam International (Nov. 2018).

with other projects against a producing field. However, what's happened in Guyana is the absence of ring-fencing provisions. As a result, ExxonMobil and its partners can deduct costs associated with either developing a new oil project or drilling an exploratory well, and all such expenditure can be charged against any project that is in operation.[230]

In a report by the Institute for Energy Economics and Financial Analysis (IEFFA) titled: "Lack of Ring-Fencing Provision Means Guyana Won't Realize Oil Gains Before 2030s, if at All," IEEFA's Director of Financial Analysis, Tom Sanzillo, noted the devastating effects of failing to have ring-fencing provisions in the 2016 Guyana-ExxonMobil PSC.[231] Sanzillo notes that ExxonMobil has already received approval of the Payara field and even made discoveries at other fields, including Yellowtail, Longtail, Uaru, Redtail, Mako, Tripletail and Whiptail in the Stabroek Block. Sanzillo noted, however, that all of the associated costs are being charged against the Liza Phase One Project thus reducing Guyana's share of the profits.[232] According to the report, it is estimated that Guyana should receive upward of $6 billion USD annually by 2028 or sooner, but because of new costs that neither ExxonMobil nor the government is disclosing, IEEFA'S Director of Financial Analysis posits, "Guyana will be short-changed until the 2030s, if not longer."[233] The IEERA report also noted that the new announcement of more discoveries, such as the one at the Whiptail site, may help ExxonMobil's stock price. However, one ought to be aware of the reality that it ultimately reduces Guyana's profits. Sanzillo stated that, "[t]he lack of contract protections means that every time Guyana announces it has received more revenue, it is actually being short-changed."[234] From a global perspective, Sanzillo stated that when the foregoing issues are placed alongside the fact that the true costs of ExxonMobil's projects, its new discoveries, and its dry holes remain unknown, the Stabroek Block deal (under the 2016 Guyana-ExxonMobil PSC) essentially leaves the people of Guyana in a dark abyss of worrisome financial risks.[235]

---

230. *Id*.

231. Tom Sanzillo, *Lack of Ring-Fencing Provision Means Guyana Won't Realize Oil Gains Before 2030s, if at All*, Institute for Energy Economics and Financial Analysis (July, 2021), https://ieefa.org/wp-content/uploads/2021/07/Lack-of-Ring-Fencing-Provision-Means-No-Oil-Gains-for-Guyana-Before-2030_July-2021.pdf (last accessed Apr. 8, 2023).

232. *Id*.

233. *Id*.

234. *Id*.

235. *Id*.

It is worth noting that ExxonMobil has defended the lack of ring fencing in the 2016 Guyana-ExxonMobil PSC. In 2019, the company's then country manager, Rod Henson, said that the absence of ring-fencing provisions was positive for a frontier country like Guyana. Henson also stated:

> The contract is working beautifully, as it was intended to do. It has succeeded to attract investors to come and find oil and develop it to the benefit of the country. So the contract is doing exactly what it was designed to do, and I think that the people should be proud of that and be very happy about where we are right now. The contract is a fair contract. It absolutely is a fair contract given the risk profile of where Guyana is. These are multi-decade agreements and we need to keep in mind that there were over 30 wells drilled in this basin, all unsuccessful, all dry holes.[236]

The Department of Energy, the Ministry of Natural Resources, and the Guyana Geology and Mines Commission all play central roles under the Guyana-ExxonMobil PSC and in the regulation of oil & gas in Guyana generally. However, the roles of these agencies are unclear, and this can lead to duplication of work and other problems. There is need for the government to urgently streamline the role of these various agencies and strengthen their institutional capacity to regulate the new energy sector.

The minister responsible for petroleum, Minister of Natural Resources, is authorized by the Act to conclude PSCs. There are several features of the 2016 Guyana-ExxonMobil PSC which have received severe criticisms by various commentators in the media in Guyana. The stabilization or renegotiation provisions, local content provisions, and decommissioning are a few which will be highlighted.

The stabilization and renegotiation clauses under the PSC are unfortunately not regulated under Guyana law. However, the model articles on production sharing agreements available through the Government of Guyana Geology and Mines Commission website refers to a "Stability of Agreement" which seeks to protect "the investment potential for the contractor against unforeseen major economic upheaval."[237] The current model PSC in Guyana is focused on protecting and attracting investments that freeze the existing laws and regulations applicable to the contract at the time of signing. However, there is not an economic equilibrium provision

236. *Id*.
237. Articles in Guyana's Petroleum Agreement, *supra* note 222.

aimed at maintaining the status quo and ensuring that in the event of windfall profits, the government will get a fair share.

Interestingly, the stabilization clause in the Guyana-ExxonMobil PSC only mentions protecting the interest of the Contractor. This is unlike an economic equilibrium clause which protects the interests of both parties. This contract is not in line with modern trends. Guyana, as a sovereign state, has the right to exercise its legislative power, and the right to enact, modify, or cancel any law at its own discretion. It can be argued that by deciding to invest, the investor takes the business risk to be faced with changes of laws or even likely to be detrimental in its investment, notwithstanding this stabilization clause. A prudent investor knows that laws will evolve over time. Apart from the freezing provisions in the ExxonMobil PSA, an IMF Assessment Report in 2017 indicated that the contract has the lowest Average Effective Tax Rate (AETR) of all the fiscal regimes evaluated.[238] This observation strengthens the argument that the fiscal terms offered in the agreement are very generous to the investor and that the contract is lopsided.

Another important aspect of the ExxonMobil PSC is that the contract stipulates for ISCID arbitration under Articles 26 and 32.4. Article 26 provides for Sole Expert and Arbitration.[239] The issue here is whether these provisions are enforceable and the proper interpretation of Article 32.4 of the ExxonMobil PSC under the Guyanese law, the governing law of the contract. Unfortunately, Articles 32.4 and 26 demonstrate that the ExxonMobil PSC is lopsided and arguably in favor of protecting the investor interest. Repeatedly, in the PSC, there is mention of protecting the contractor's economic benefits while no mention is made of protecting the interests of the State. Ironically, while the contract makes mention of "generally accepted customs and usages of the international petroleum industry", and states that the contractor and sub-contractors shall operate in a manner as is "customary in the international petroleum industry in accordance with good oil field practices," it can be argued that the very core of the contract does not adhere to general international petroleum industry practices.

The ExxonMobil PSC received severe criticisms by various commentators in the media in Guyana. It has been argued that the contract should be

238. Stabroek News*, supra* note 227. The revenue generating capacity of the fiscal regime is evaluated by estimating the Average Effective Tax Rate (AETR) or "government take." The AETR is calculated as the ratio of government revenue to the project's pre-tax net cash flows over the life of the project using a discount rate.

239. 2016 Guyana-ExxonMobil PSC, *supra* note 225, at art. 26.

renegotiated.[240] While there has been a series of calls for the government of Guyana to renegotiate the ExxonMobil PSC, the newly formed Department of Energy has made it clear, on several occasions, that it will not be pursuing the renegotiation of the contract.[241]

It should be noted that regarding local content, the PSC stipulates that the Contractor shall make "reasonable efforts" to train Guyanese suppliers and Sub-Contractors in the mechanics of participating in tenders and competing for contracts to be offered pursuant to the petroleum operations. The term "reasonable efforts" is an ambiguous phrase. The local content provisions in the 2016 PSC from Guyana does not stipulate specific training requirements. In 2020, Guyana released a local content policy specifically for the petroleum sector.[242] However, the Guyanese local content policy and future PSCs with international oil companies do not include succession plans for the employment of Guyanese individuals in the industry. It is recommended that PSCs in the future stipulate that international oil companies must agree that they will, as far as possible, employ qualified Guyanese nationals in the petroleum operations and require their contractors and subcontractors to do the same. Further, there should be the obligation for the international oil companies to give priority to Guyanese nationals with equivalent qualifications and experience, and for the international oil companies to gradually replace a percentage, such as 80% of its expatriate staff with qualified Guyanese nationals within a given time frame, such as four years after the license is granted.

The provisions under the 2016 Guyana-ExxonMobil PSC dealing with decommissioning must be highlighted. Historically, little attention was paid to the issue of decommissioning in Guyana. 'Abandonment' was the original term used in various laws, regulations, and contractual provisions in Guyana. This term is still used in many legal documents today. The 1986 Petroleum

240. *ExxonMobil contract illegal; irretrievably flawed and is either the result of grand corruption or grand incompetence*, *supra* note 227.

241. Kiana Wilburg, *Energy Dept. taking incorrect stance on important issues- Should be focused on renegotiation of oil contracts, etc. – Dr. Mangal*, Kaieteur News (Apr. 16, 2019), https://www.kaieteurnewsonline.com/2019/04/16/energy-dept-taking-incorrect-stance-on-important-issues-should-be-focused-on-renegotiation-of-oil-contracts-dr-mangal/; Kiana Wilburg, *Don't be fearful of renegotiation…Exxon will not walk away from Guyana, no matter what –says Houston University Instructor*, Kaieteur News (May 19, 2019), https://www.kaieteurnewsonline.com/2019/05/19/dont-be-fearful-of-renegotiation-exxon-will-not-walk-away-from-guyana-no-matter-what-says-houston-university-instructor/.

242. *See Guyana Petroleum Sector Realising Local Content Benefits and Value Retention from Guyana's Petroleum Resources* (January 2020), https://oilnow.gy/wp-content/uploads/2020/02/local-content-benefits.pdf.

Regulations are the most significant instrument which focuses on decommissioning in Guyana. The 1986 Guyana Petroleum (Exploration and Production) Act does not mention the terms ‘abandonment’ or ‘decommissioning’ while the 1986 Petroleum Regulations mention abandonment once and provide for the removal of property at the end of the production by the petroleum production license holder under Regulation 9.[243]

The 1986 Petroleum Regulations also provide that the holder of a license shall furnish to the Minister, through the Chief Inspector, the following: reports, data, and other information and samples acquired in the course of prospecting operations under the license, within one week after completion of any drilling or geological operations, abandonment, suspension and completion design under Regulation 25(3).[244] Additionally, Regulation 6(5) provides that a licensee shall furnish to the Chief Inspector reasonable notice of its intention to abandon any well giving reasons therefore and the techniques to be used therein, and the closure or plugging of any well shall be carried out only with the prior consent in writing of the Minister and in the manner approved by him.[245]

Turning to the Guyana- ExxonMobil PSC, Article 20 provides that “(a)ll funds required to carry out the approved abandonment program shall be made available by Contractor when the cost for abandonment are incurred”[246] and “(a)ll costs included in the approved abandonment programme and budget shall be Recoverable Contract Costs as operating costs…”[247] In addition to the 1986 Petroleum Regulations and the ExxonMobil PSA, a few other laws prescribe obligations relating to abandonment and decommissioning activities in Guyana.[248]

Here again, Guyana’s legislative framework needs revision to include decommissioning provisions that are satisfactory considering current best practices in the energy industry, as well as the country’s domestic and international law obligations. A major gap in the laws and regulations of Guyana is that there is no requirement for a decommissioning fund or for monies to be placed in an escrow account. The weakness of the legislative framework in Guyana is further compounded when one reviews the

243. The Petroleum (Exploration and Production) Act, *supra* note 220.

244. The Petroleum Regulations, *supra* note 221 at 25 (3)(iii) (E).

245. *Id.* Reg. 6(5).

246. 2016 Guyana-ExxonMobil PSC, *supra* note 225.

247. *Id*. at art. 20.1(d) (iii) (ff) & (gg).

248. *See* Environmental Protection Act, (no. 11 of 1996), Laws of Guyana; see also Environmental Protection (Amendment) Act (no. 17 of 2005), Laws of Guyana.

ExxonMobil PSA.[249] As pointed out above, there is no pre-funding required nor fund created under Article 20 of the ExxonMobil PSA. This is unusual by today's oil and gas industry standards. Article 20 provides that "(a)ll funds required to carry out the approved abandonment programme shall be made available by Contractor when the cost for abandonment are incurred" and "(a)ll cost included in the approved abandonment programme and budget shall be recoverable contract costs as operating costs…"[250]

c) Brief explanation about solutions adopted or at least considered to solve the said challenges and concerns.

As stated above, there is no comprehensive model production sharing agreement available by the Government of Guyana for prospective investors. Guyana is a relatively new frontier in the petroleum industry, and the legal framework as well as model production sharing contracts governing oil and gas exploration and production are outdated.

One recommendation is for the model production sharing contracts in Guyana to be changed to be more profit-sharing regime. Under this model, after an international oil company has recovered its costs, profits must be shared between the company and the host government, based on a sliding scale profit-sharing formula related to the rate of return of the producing international oil company. This formula should also be used for bid rounds. One of the factors for determining the successful bidder should be the company that offers the highest bid to the government.

The 2016 Guyana-ExxonMobil PSC did not fill the gap and provide protection where the law was lacking. As a result, there is a need for urgent law reform in several areas, such as to prescribe laws which address decommissioning, local content, stabilization, and several other areas. The laws and regulations in Guyana, as well as the model PSCs currently being used by the Geology and Mines Commission and the Department of Energy, do not contain satisfactory provisions to protect the interest of Guyana. Guyana would benefit from creating a model PSC which includes provisions aligned with best industry practices. Also, the recommendation of the IMF and several other international bodies supports that the government of Guyana put together a model PSC which includes the minimum fiscal terms or package to be accepted for future contracts.

249. 2016 Guyana-ExxonMobil PSC, *supra* note 225.
250. *Id*. at art. 20.1(d) (iii) (ff), (gg).

3.8. Trinidad and Tobago

a) Brief explanation about the evolution of PSCs and cost recovery in your jurisdiction

Trinidad and Tobago has over 100 years of experience in oil and gas exploration and production.[251] It is the largest oil and natural gas producer in the Caribbean islands and territories. Trinidad and Tobago's long-established record in offshore commercial oil and gas accounts for approximately 66% of the region's offshore oil production and 98% of natural gas, compared with Cuba's 29% of oil production.[252] From the discovery of the first oil deposits in 1867, Trinidad and Tobago has gained considerable experience in oil and gas exploration activities onshore and in shallow waters, with the cumulative production totaling over 3 billion barrels of oil. In the early 1990s, the country's hydrocarbons industry shifted from oil-dominated production to a market centered primarily on natural gas.[253] Oil production in Trinidad and Tobago peaked at 193,000 bpd (barrels of oil per day) in 2007 and has suffered a steep decline since then, to 99,000 bpd in 2017. The decline in output is mainly attributed to the increasing difficulty of extracting resources from the country's mature fields, as well as low oil prices and subsequently lessened exploration efforts. In 2017 and 2018, headway was made in enhanced oil recovery (EOR) projects aimed at mitigating the crude production decline.

---

251. *See White Paper on National Minerals Policy 2015*, Energy.gov (June 2015), http://www.energy.gov.tt/wp-content/uploads/2014/01/White-Paper-on-National-Minerals-Policy-June-2015.pdf; *see also Trinidad and Tobago Extractive Industries Transparency Initiative Report 2016*, Extractive Industries Transparency Initiative (last visited Apr. 8, 2023) http://www.tteiti.org.tt/wp-content/uploads/TTEITI-Report-2016.pdf.

252. Pawan G. Patil, John Virdin, Sylvia Michele Diez, Julian Roberts, & Asha Singh, *Toward A Blue Economy: A Promise for Sustainable Growth in the Caribbean; An Overview*, World Bank Group (last visited Apr. 8, 2023), https://documents1.worldbank.org/curated/en/965641473449861013/pdf/AUS16344-REVISED-v1-BlueEconomy-FullReport-Oct3.pdf; *see generally The Oil & Gas Year Trinidad and Tobago 2019*, The Energy Year (last visited Apr. 8, 2023), https://www.theoilandgasyear.com/market/trinidad-and-tobago-2/; *see also Historical facts on the Petroleum Industry of Trinidad and Tobago*, Government of the Republic of Trinidad and Tobago, http://www.energy.gov.tt/historical-facts-petroleum/ (last visited Apr. 8, 2023).

253. *See* Government of the Republic of Trinidad and Tobago Ministry of Energy and Energy Industries, 'A Draft Energy Policy for Trinidad and Tobago: A Green Paper' (1998); *Oil and Gas Industry: Overview*, Government of the Republic of Trinidad and Tobago Ministry of Energy and Energy Industries (last visited Apr. 8, 2023) http://www.energy.gov.tt/our-business/oil-and-gas-industry/.

The evolution of Production Sharing contracts in Trinidad and Tobago is governed by various pieces of legislation. The key legislation is the *Petroleum Act and Regulations*.[254] This legislation governs the conduct of petroleum operations. The Act and Regulations together establish a regulatory framework for the grant of Exploration and Production Licenses ("E&P Licenses") and Production Sharing Contracts ("PSCs") for the conduct of upstream exploration and production operations, including activity on land and in the submarine areas beneath the territorial waters and the continental shelf of Trinidad and Tobago. The Act and Regulations also regulate several other types of petroleum operations apart from upstream exploration and production. The primary regulator of the industry is the Minister of Energy and Energy Industries ("the Minister"), who acts through the Ministry of Energy and Energy Industries ("the MEEI").

Exploration and Production Licenses were the main contractual arrangements used during the 1900s–early 1970s by the Government of Trinidad and Tobago. However, given the rapid development of the sector, better administration of the contractual arrangements is necessary. In 1974, the first two Production Sharing Contracts (PSCs) for acreage off the east coast of Trinidad were signed. These earlier PSCs did not provide for cost recovery. They allowed the government a share of production based on production levels and were ring-fenced.

In 1995, the government of Trinidad and Tobago adopted the World Bank PSC Model. This PSC included expanded and enhanced contractual terms and conditions. These included provisions for cost recovery, relinquishment, abandonment, shares of Profit Petroleum for the government that were based on both price and production levels, and minimum work obligations during the exploration period. It also included a procedure to encourage the development of natural gas markets and financial obligations such as signature bonus, research and development, training of nationals and technical equipment bonus. Like the earlier PSCs, these continued to be ring-fenced and assured the Government of a steady revenue stream. In addition, under these PSCs, the Contractor's tax liabilities were paid by the Government out of its share of profit petroleum. Simultaneously, similar type

254. Laws of Trinidad and Tobago Petroleum Act, act 46 of 1969 (updated Dec. 31, 2011), https://www.elaw.org/sites/default/files/content_type_law_attachment/Petroleum%20Act%201969.pdf; *see also* Laws of Trinidad and Tobago Petroleum Regulations (Legal notice 5 of 1970).

provisions were slowly being introduced in the Exploration and Production (Public Petroleum Rights) Licenses (E&P licenses).[255]

A review of the petroleum fiscal regime undertaken in 2005, led to the introduction of a new styled PSC, referred to as a "taxable PSC" that introduced three major features. Firstly, the Government received a share of Profit Petroleum in lieu of some taxes *viz* Supplemental Petroleum Tax, Royalty, Petroleum Impost and Petroleum Levy. Contractors were therefore exempt from payment of the taxes but required to pay all other taxes, namely, Petroleum Profits Tax, Unemployment Levy, Green Fund Levy and Withholding Tax, directly to the Ministry of Finance. This represented a departure from the earlier models in which the government paid these taxes on behalf of the Contractor. Secondly, a windfall profits feature was introduced to capture higher shares of profit petroleum as petroleum prices increased. Thirdly, consolidation of the new PSCs, by type - either deep water or land/shallow marine- was permitted. This was to promote multi-block development and facilitate investment by consortia and in so doing minimize their exposure to risks.

Also included were provisions for re-openers, accessibility of natural gas supplies for both the domestic and export markets, improved funding procedures for abandonment, and assignments and transfers. A special incentive that provides for an uplift of 40% on the drilling of exploration wells in the deep water was also introduced. In 2010, the legislation regarding the "taxable PSC" was repealed and the 1995 model PSC was reintroduced. It included the following changes: cost recovery levels fixed at 50%, 55%, and 80% for shallow, average, and deep-water areas respectively; financial obligations are also fixed and the only two biddable items are the Government's profit share and minimum work program; and signature bonus was no longer compulsory."[256]

Under *The Petroleum Act,* companies are required to pay a royalty that is stipulated in the license, as well as contribute to the Petroleum Impost, which is used to cover the administrative costs of the Ministry of Energy. Royalty rates vary based on policies in existence at the time of the execution of the license. For crude oil, the rate ranges from 10% to 12.5% of the Field Storage Values. According to the website of the Ministry of Energy and Energy

255. *Id*., *see* Part 1 of Laws of Trinidad and Tobago the Petroleum Act, no. 46 of 1969, Cap. 62:01 (for application procedure, conditions to be included in the licences, etc. for the Exploration and Production (Public Petroleum Rights) Licences).

256. *See id*., *Tax Laws*, Government of the Republic of Trinidad and Tobago Ministry of Energy and Energy Industries http://www.energy.gov.tt/for-investors/fiscal-regime/tax-laws/, accessed 06/24/2021.

Industries,[257] "up until 1989, the Field Storage Value was based on the Royalty Lease Evaluation 1 Method (RLE1)."[258] This method provides for a price for crude oil that was determined by the values of the crude oil fractions (light oils, diesel, and fuel oil) less a percentage for refining and handling charges. For licenses signed from 1989, the Field Storage Values are determined using international market prices of reference crudes. In the case of natural gas, the royalty rate ranges from 0% to 15%.

The *Petroleum Production Levy and Subsidy Act* was passed in 1974 with the objective of buffering large increases in petroleum product prices and providing a general level of market stability.[259] This Act established a Petroleum Products Subsidy Fund to be managed by the Minister of Finance. Subject to the Act and to any Regulations and Orders made thereunder, the Minister of Finance is authorized to cause advances to be made from the Fund for the purpose of subsidizing the prices at which petroleum products are sold by persons carrying on marketing business in accordance with price-fixing Orders made by the Minister under section 31 of the *Petroleum Act.* In 1992, the Act was amended to place a ceiling on each company's gross levy payments of not more than 3% (later increased to 4%) of its value of gross income derived from the sale of crude.[260] An inclusion was also made of those companies, previously exempt with production level of less than 3,500 barrels of oil per day. Any excess levy payments above the cap are to be made by the Government.

Taxation of Petroleum companies is governed by the provisions of the *Petroleum Taxes Act*.[261] Chap 75:04, which applies to all companies engaged in petroleum operations, is defined therein as hydrocarbon compounds, "petroleum operations" means the operations related to the various phases of the petroleum industry, and includes natural gas processing, exploring for, producing, refining, transporting and marketing petroleum or petroleum products or both, and manufacturing and marketing of petrochemicals; but

257. See Government of the Republic of Trinidad and Tobago Ministry of Energy and Energy Industries, *Tax Laws* http://www.energy.gov.tt/for-investors/fiscal-regime/tax-laws/ (last accessed Apr. 8, 2023).

258. *Id.*

259. *Petroleum Production Levy and Subsidy Act* Chap 62:02, Laws of Trinidad and Tobago.

260. *See* Laws of Trinidad and Tobago Petroleum Profits Tax, Ch. 75:04, https://rgd.legalaffairs.gov.tt/laws2/alphabetical_list/lawspdfs/75.04.pdf (last accessed May 9, 2023).

261. *See Id*.

does not include mining operations involving the extraction of petroleum from bituminous shales, tar sands, asphalt or other like deposits.

Under the Act, two main taxes are paid by petroleum companies. These are *Petroleum Profits Tax* (Part 1 of the Act) and *Supplemental Petroleum Tax* (Part 11). The Petroleum Profits Tax (PPT) is applicable to all oil and gas producers as well as refinery operators and is applied to the net profits, chargeable income, from operations. The calculation for the net profit is derived by deducting all operating expenses, capital allowances, and other allowable deductions from the gross income. According to the Ministry of Energy and Energy Industries, deductions for oil and gas producers include royalties, Supplemental Petroleum Tax, Petroleum Levy/Impost, decommissioning/abandonment costs and management fees paid to non-resident companies (limited to 2% of expenditure).[262] Other special allowances are granted for signature and production bonuses, dry holes, workovers, qualifying side-tracks, heavy oil and exploration costs, the latter available for the years 2014 – 2017. The current applicable tax rate charged on producers as well as refinery operators is 50%, reduced to 35% from income year 2011 for deep water operations only. Over the years, amendments have been made to the PPT as market conditions changed. According to the Ministry of Energy and Energy Industries, the last change was in 2014, when increased allowances granted on capital expenditure.[263]

The Supplemental Petroleum Tax (SPT) was introduced in1981 by Act 5 and has been amended on several occasions. The SPT imposes income generated from production of crude oil net of royalty and over-riding royalty. Prior to 2005, SPT was levied on the gross income from the disposals of crude oil, not natural gas income, less certain allowances based on expenditure incurred in specified exploration and development activities. Although the tax was imposed on crude oil sales, companies involved in both oil and gas activities benefitted from the allowances since they were broadly applied to exploration and development field activities. This significantly contributed to the development of the natural gas industry in Trinidad and Tobago.

Over the years, the Supplemental Petroleum Tax rates varied for offshore and onshore operations and for licenses and contracts that were agreed prior or post 1988. In 2006, SPT rates for deep-water operations were fixed for land operations post-1988. SPT rates were also based on a sliding scale for prices ranging from $15.00 to $49.50 USD per barrel. Thereafter, the rate

262. *See Tax Laws, supra* note 261.
263. See *Id*.

remained fixed. As time progressed and as economic and industry factors warranted, several amendments were made to this tax. During the period between 2011 to 2013, incentives in the form of discounts/ tax credits were introduced to further stimulate the production of crude oil.

According to the Ministry of Energy and Energy Industries, companies also pay 5% of the chargeable income before loss relief plus any exempt income under the *Unemployment Levy Act* and the monies obtained are applied to assist in the Government's social programs.[264] The Green Fund Levy equates to 0.3% of the gross sales or receipts and is paid under the *Miscellaneous Taxes Act.*[265] The purpose of this levy is the restoration and preservation of the environment.

b) Brief explanation about the challenges and concerns with PSCs and cost recovery in your jurisdiction

Trinidad and Tobago is a mature oil and gas province and will need to balance the desire for proper fiscal regulations in the energy sector along with the need to make the offerings to investors attractive. In the past, the government of Trinidad and Tobago shared model PSCs for negotiation. However, the actual terms of the final agreement were not made public. It is recommended that to promote transparency and accountability, the actual final agreements be shared by the government.

Also, the government of Trinidad and Tobago previously offered its own model Joint Operating Agreement (JOA) form, which is the model JOA from the Association of International Petroleum Negotiators (AIPN). The JOA has been used with the E&P Public Petroleum Rights License for onshore operations, whereas the Model PSC together with that licence was used for offshore operations only. This model JOA has been used in several cases, especially regarding onshore operations with the national oil company having a participating interest in the joint operations. The Petroleum Company of Trinidad and Tobago Limited (Petrotrin), the national oil company, was incorporated in 1993 and was wholly owned by the government. The company was mandated to engage in petroleum activities along the sector value chain and for several years, Petrotrin owned and operated the only refinery in the country; in late 2018, the government took

264. Law of Trinidad and Tobago Unemployment Levy Act, Ch. 75:03, https://www.energy.gov.tt/wp-content/uploads/2021/07/Unemployment-Levy-Act-75.03.pdf (last accessed May 9, 2023).

265. Laws of Trinidad and Tobago Miscellaneous Taxes Act, Ch. 77:01, https://agla.gov.tt/downloads/laws/77.01.pdf (last accessed May 9, 2023).

the decision to close it down due to financial and other reasons.[266] This development raises challenges for JOAs and PSCs in Trinidad and Tobago.

c) Brief explanation about solutions adopted or at least considered to solve the said challenges and concerns.

It is commendable that since 2005, the Government of Trinidad and Tobago has made some progressive changes to its PSC model. Under this new PSC model, the government of Trinidad and Tobago has implemented a profit-sharing regime. This means that after the international oil company recovered its costs, profits are shared between the company and the host government, based on a sliding scale profit-sharing formula (which varies from 50% to 80%) related to the rate of return of the producing international oil company or their production tier per barrel of oil or oil equivalent per day.

As highlighted above, the government of Trinidad and Tobago should not only publicize the model PSCs which it uses for negotiation, but the final negotiated agreements should also be made public. This will help to promote transparency and accountability. The government of Trinidad and Tobago should also adopt a new policy regarding the use of PSCs and JOAs since Petrotrin is now closed. It is recommended that PSCs be utilized for both onshore and offshore exploration and production.

4. Lessons learned

At the time of writing, the oil and gas industry is at a crossroads, some would say a cul-de-sac. The pattern of price fluctuations, which began with the Asian financial crisis in 1998, continues with only greater intensity. The WTI[267] futures price reached $-37 a barrel in April 2020, although this was a localized and temporary phenomenon. Twenty months later, the Brent crude price is approaching $100 USD per barrel. The global economic slowdown triggered by the Covid-19 epidemic led to a very significant retrenchment in

266. *See* Darlisa Ghouralal, *Petrotrin closed; $2.7 billion paid out to workers*, Loop (Nov. 30, 2018) https://tt.loopnews.com/content/petrotrin-closed-27-billion-paid-out-workers; Rosemarie Sant, *Petrotrin to shut down November 30*, Trinidad and Tobago Guardian (Sept. 28, 2018) http://www.guardian.co.tt/news/petrotrin-to-shut-down-november-30-6.2.678617.781afbbf9e.

267. *West Texas Intermediate*, Nasdaq (last visited Apr. 8, 2023) https://www.nasdaq.com/glossary/w/west-texas-intermediate (West Texas Intermediate (WTI) oil is a benchmark used by oil markets, representing oil produced in the U.S. WTI is the underlying asset in the New York Mercantile Exchange's oil futures contract. This type of oil has a low sulphur content (sweet). The U.S. Department of Energy maintains historical data for this oil price. It is sometimes known as WTI - Cushing or WTI, Cushing, Oklahoma).

capital investment by the industry, leaving it in poor position to ramp up production as global demand increased. Furthermore, the oil markets are not convinced that the key producer states, such as Saudi Arabia and the US, have the marginal production capacity immediately available to meet such renewed demand.

In this context, it is important to understand the position of key producer states, particularly in Latin America, Africa, and South-East Asia, which have used production sharing agreements to build a portfolio of hydrocarbon-based income to the state budget, usually deploying such income for internal purposes, relying upon the international oil companies to deliver ongoing investment. These portfolios often rely upon a cluster of large or very large hydrocarbon reservoirs which have been in production for several decades, and their end is in sight. To avoid a falloff in hydrocarbon production and state revenue, the states need to encourage new investment, either in new fields or in enhanced oil recovery projects, or both. All such investment necessarily comes with a significant time delay, particularly in the case of new field development.

These market dynamics also play out in the context of climate change and pivot towards the reduction or elimination of fossil fuels from energy supply. Financial markets are increasingly deterred from lending to hydrocarbon projects because of their commitments to their stakeholders to meet decarbonization targets, whereas the producer states are struggling to cope with ever larger debt burdens caused by the Covid 19 epidemic. Oil and gas company investors themselves are also under pressure to reduce carbon emissions, their investment decision-making is increasingly driven by their carbon and capital budgets. Both states and business have made their commitments to achieve carbon neutrality over time, but few have issued detailed implementation plans, making it difficult to guess what role hydrocarbons will play in hydrocarbon–dependent economies over the next three decades.

These "modern" concerns compound the long-standing issues with respect to cost recovery, e.g., Indonesia and Kazakhstan, the deterrent effect of uncertainty over the approval of recoverable costs before and after they are incurred, the state's anxiety over "gold plating" and the very expensive and protracted disputes that may then arise. On the one hand, the contractor would expect the state to give it a level of confidence that the costs of a certain investment will be recoverable before going ahead. On the other hand, the state is reluctant to guarantee cost recovery in respect of an investment which is not predictable—after all, its purpose in awarding a production sharing agreement was to transfer such risk to the contractor. Therefore, state bureaucrats do not wish to be associated with the approval of costs which do not yield the anticipated levels of hydrocarbon production or with questionable origin. From such perspective, the bureaucratic delays in obtaining state approval of costs for recovery purposes is common to occur due to the said governmental concerns.

As was discussed in the Kazakhstan chapter, such concerns are amplified if the cost recovery approval process is treated by the state as a function of tax administration, bringing to bear tax rules and tax penalties. This sometimes involves the allegation of criminal fraud and tax evasion since the amount of money in dispute between contractor and state can be very significant. In this situation, the contractor may legitimately feel that threats of criminal litigation against its personnel with respect to cost recovery do nothing to facilitate the resolution of cost recovery dispute by negotiation. In states where allegations of financial corruption are commonplace, the state may apply its fiscal rules inflexibly to avoid any allegation of favoritism towards the contractor. Whereas the production sharing agreement itself may, in its dispute resolution clause, require the parties to negotiate any dispute in good faith before resorting to formal litigation such as international arbitration. Indeed, the result can be that the state drives the parties towards litigation instead of amicable resolution of cost recovery issues because its bureaucrats do not want to be associated with a settlement that compromises the state's uncompromising fiscal rules.

Given such complexities, and increasingly competitive environment for oil and gas capital, it is not surprising that Indonesia is moving away from PSCs built around cost recovery, replacing them with sophisticated models for production splits instead.

What can such states do to attract investment within the context and limitations of the production sharing contracts they have already signed or are part of their standard terms for tendering new acreage?

It is useful to answer this question in the context of two possible strategies—firstly, the encouragement of further investment in existing producing fields with a view to extending field life and postponing the decline in production levels, and secondly the licensing of new acreage, with a view to adding further hydrocarbon sources to the state's portfolio. While each state discussed in these papers has made efforts to encourage investment by adjusting their PSC regimes, it is arguable that PSC's themselves do not provide the best basis upon which to encourage such new investment for the reasons discussed below.

Extending field life by enhanced oil and gas recovery, or EOR, is immediately attractive because it involves increasing delivery of hydrocarbons from an existing reservoir with no exploration risk. This is because the reservoir is known and better understood, due to data collected from producer wells. The oil companies may consider drilling fresh producer wells to access compartments of the reservoir not previously exploited, may install reinjection wells by which gas or water is reinjected into the reservoir to increase or maintain reservoir pressure, and/or may install surface compression facilities to support such reinjection. Nevertheless, the investment required is very significant and relies upon assumptions with respect to the reservoir which may prove incorrect.

The state and oil & gas company investors may not be aligned on the attractiveness of EOR campaigns. Firstly, because the PSC may expire before the investor can expect full recovery of the costs of the EOR campaign from cost oil and/or a decent yield of incremental profit oil. The term of any PSC is set when it is signed before the parties can form any view as to the likely producing life of any reservoir discovered within its contract area. As a result, discussions around EOR may necessarily trigger discussions about the extension of the PSC. On the one hand, the state might consider allowing the PSC to expire, with a view to awarding a fresh PSC to an investor ready and willing to undertake the EOR project on different terms, but can the state afford to wait for the existing PSC's expiry? On the other hand, if the existing PSC investor is not convinced of the value of the EOR campaign or more likely has competing opportunities for the investment of its carbon and capital budgets, it may need to be offered amended PSC terms to encourage it to undertake the investment. As illustrated by this paper, the PSCs in place are likely to be the subject of stabilization, and the state is unable to change their terms unilaterally, or by changes in domestic legislation. Nor is it likely that the state will be able to force the investors to conduct the EOR campaign unless it is economically attractive to both sides. Many PSCs will provide that the investor is obliged to take reasonable steps in accordance with good oil field practice to maximize production from the reservoir, and this obligation is likely to have been crystallized in a field development plan approved by the state when the field development plan was first approved. Any production targets in that development plan which are dependent upon further investment in production facilities are likely to be described in the development plan as options, subject to further approval by state and investor. Oil and gas companies protect their right to make decisions on the allocation of their capital budget beyond the capital committed by the final investment decision or FID which approved the field’s development in the first place.

Accordingly, the state may find itself obliged to revisit the PSC terms to encourage investment by the existing parties. Unless the state is generous in extending the terms of the PSC, the investors may reasonably require that any cost recovery limit is lifted to accelerate cost recovery before the PSC expires. This is hardly attractive for the state because it means that cost recovery is prioritized above the allocation of profit oil. So, the state's income is deferred, conflicting with the state's objective of using the income from incremental oil production to offset the decline in income from the original investment. On the other hand, the PSC may offer the parties some room for maneuver; the investor is likely obliged to make contributions to an abandonment or decommissioning fund during the final years of the PSC. Such decommissioning fund contributions will be cost recoverable. If the EOR campaign is approved and the PSC expiry date is postponed, those decommissioning contributions can also be deferred, replacing the allocation of cost oil to cover such contributions with the allocation of cost oil to cover the capital costs of EOR.

Nevertheless, these negotiations are likely to be difficult because they overlap the PSCs existing balance of commercial interests. They may cause the parties to revisit existing controversies and disputes over the PSCs existing terms and past costs. In that case they may find themselves obliged to ring fence the future costs of the EOR project to which new terms may exclusively apply. This is not a recipe for confidence building.

Alternatively, the state may consider encouraging investment in new acreage. None of the states discussed in these papers allow an investor to recover the costs of exploration other than through income from the sale of production on a ring-fenced basis. It is therefore not an attractive model for encouragement of exploration of a mature basin where, likely, the larger reservoirs have already been found and exploited. Bear in mind that even investors in existing reservoirs are likely to have been required to relinquish acreage outside the specific area of such reservoirs, at the conclusion of the exploration phase of their PSC. This will mean that adjacent acreage will have to be re-awarded to them under the terms of a fresh PSC, with no prospect of exploration costs under such fresh PSC being offset against production revenue from the existing PSC.

Nevertheless, the economics of developing any fresh discovery will be affected by the availability of existing production, processing, and transportation facilities. A marginal discovery may be commercial only if it can access spare throughput capacity in such facilities already built. Even if that were not the case, the state and investor would benefit greatly from avoiding further capital investment in fresh facilities. Any use of existing facilities to produce and transport production from a new PSC would however require another round of discussion between the new PSC parties, the owners of the facilities and the state, to satisfy the state that the cost recovery ring fences surrounding each PSC were being respected, and the existing PSC was not cross subsidizing the new one. This would particularly be the case if the fiscal terms of the new PSC were more generous than the fiscal terms of the existing PSC.

5. Conclusion

Cost recovery is an essential element behind the production sharing system, where you need to consider the costs involved to allocate the profit sharing of the relevant parties. As discussed, it might be complex from a governmental perspective to audit such costs in a timely and detailed manner, as the country increases the number of signed PSAs. Therefore it is important for a host government to understand the growth of its upstream sector, along with the tools it might have available to determine the best way to audit such costs and they might pose further challenges in mature provinces.

Therefore, it is worth revisiting one of the original rationales for choosing production sharing as the preferred model for hydrocarbon exploitation: to encourage investment in states whose petroleum legislation was at an early stage of development, production sharing offered the opportunity for the investor and state to agree a bespoke fiscal regime and to accelerate investment in hydrocarbon prospects. In the following decades, the host states have refreshed and renewed their petroleum legislation several times, often introducing alternative mechanisms such as risk service contracts, and tax and royalty contracts. Simultaneously, national oil companies have developed significant economic autonomy and financial strength. For these reasons, the PSC model may not be optimal for the proposed licensing of marginal acreage because of the cost recovery ring fence and the exploration risk which is entirely allocated to the investor. One mechanism by which existing PSC's and licenses for new acreage may coexist is a PSC investor to offset exploration costs in the relevant host state against its corporate income tax chargeable on all its taxable income in country, including its share of PSC production revenues. That would allow the PSC cost recovery ring fence in place, protecting the state's profit oil share, whilst allowing the investor the prospect of offsetting its exploration costs against taxable receivables in real-time.

Appendix: Author Biographical Information

Eduardo G Pereira is a professor of natural resources and energy law as a full-time, part-time, honorary, associate, adjunct, researcher and/or visiting scholar in a number of leading academic institutions around the world. He has been active in the oil and gas industry for more than 15 years and is an international expert on joint operating agreements. His experience in this area—both academic and practical—is extensive. He has practical experience in over 50 jurisdictions covering America, Europe, Africa and Asia. Prof. Pereira concluded his doctoral thesis on oil and gas joint ventures at the University of Aberdeen. He conducted postdoctoral research at Oxford Institute for Energy Studies (University of Oxford, UK), the Scandinavian Institute of Maritime Law (University of Oslo, Norway) and is currently conducting postdoctoral research at the Institute of Energy and Environment (University of São Paulo, Brazil). He is also a managing editor for the GSENRLJ and an associate editor of OGEL. He is also the author and editor of several leading oil and gas textbooks. Further information about his profile and publications can be found at: www.eduardogpereira.com

Reg Fowler is a legal consultant with more than 25 years providing English international law advice to oil majors operating in the UK, Russia, Kazakhstan and Africa. For example, he has managed exploration projects and operating assets in the Southern Gas Basin of the North Sea, looked after Shell's interests in the giant Kashagan field in Kazakhstan up to and including its start-up in 2016, planned the replacement of the Tyra facilities offshore Denmark and have been embedded in the Karachaganak joint venture in North West Kazakhstan during its expansion and the Covid 19 epidemic. Between 2001 and 2008, he was based in Shell's oil and gas trading office in London, and developed considerable expertise in physical and derivative commodity trading. Presently he acts as general counsel for a start-up company operating in the carbon markets, leveraging his trading experience. He is also co-authored a proposal promoting a multilateral investment treaty to encourage investment in green energy which was submitted for debate by G20 in Indonesia in September 2022.He also advises an oil and gas exploration company active offshore Africa.

Thomas Kojo Stephens obtained his Bachelor of Arts in Political Science and Philosophy (Highest Honours) from Emory University in Atlanta, GA, which he attended as a Bill Gates Scholar, graduating Summa Cum Laude, Phi Beta Kappa. He obtained his LLB from the University of Ghana, Legon, QCL from the Ghana School of Law, and LLM from Cornell University, Ithaca, USA. He attended the University of Aberdeen, Scotland, UK as a

Commonwealth Scholar and obtained a PhD in Petroleum Law, Policy and Regulation. He is a Notary Public, a Senior Partner at Stobe Law and the Head of the Transactional and Energy Practice, as well as the Consultancy Group of the firm. He advises numerous entities in the energy sector and serves as principal consultant for a number of high-profile entities. He is the jurisdictional author for a number of international publications in Energy Law and has written on different facets of the industry. He is an Advisory Board Member of the International Energy Law Advisory Group (IELAG), a Principal Trainer at the International Energy Law Training and Research Center (IELTRC), a guest lecturer in Petroleum Law at the University of West Indies and was Vice-Chairman of Ghana's Public Interest and Accountability Committee (PIAC) from 2018-2020, a statutory body with oversight over the use of Ghana's petroleum revenue. He is a Senior Lecturer at the University of Ghana School of Law (UGSoL) where he lectures and serves as a Coordinator in both the LLB and LLM Programs, lecturing among others, Natural Resources Law, Conflict of Laws/Private International Law, and Energy Law, Policy and Practice, supervises in the PhD Programme, and serves as Chair of the University's Disciplinary Board for Junior Members.

Alicia Elias-Roberts is currently the Deputy Dean in the Faculty of Law at the UWI St Augustine Campus in Trinidad and Tobago. She teaches Oil and Gas Law and International Environmental Law at the University of the West Indies (UWI) St Augustine Campus. She is a former Head of the Department of Law at the University of Guyana. Alicia Elias-Roberts is a graduate of Queen's University (Canada), where she obtained her PhD, focused on Energy and International Law. Alicia has a Law Degree (LL.B.) from the University of Guyana. She is also a graduate from the University of Oxford in the UK where she obtained a Masters of Law (BCL) and she is the recipient of a LLM in Energy, Environment and Natural Resource Law from the University of Houston in Texas, USA, where she was an OAS/LASPAU scholar. Alicia is also the recipient of a United Nations fellowship in International Law. Alicia has over 20 years' experience as an energy and environmental law academic and consultant. She was previously a Legal Treaty Consultant with the Caribbean Community (CARICOM) Secretariat and has done legal consultancies for UNAIDS, ILO, PAHO, and various governments in the Commonwealth Caribbean. She has written over 20 journal articles, chapters in books and edited books with publishers around the world and she has provided expert legal advice in the areas of oil and gas law, conservation and biodiversity law, multilateral environmental agreements, maritime law, treaty law, and procurement law, to name a few.

She is an attorney-at-law, admitted to practice in New York, USA, Trinidad and Tobago and Guyana.

André Lemos is a senior associate in the oil and gas practice of Lefosse Advogados. He has expertise in the development of projects in all segments of the oil and gas industry (upstream, midstream and downstream). André has extensive experience in M&A transactions (and asset deal), complex contracts and regulatory matters, as well as in bid rounds organized by the Brazilian National Agency of Petroleum Natural and Biofuels - ANP. André is also committed to academic research and has published numerous papers on matters related to the Oil and Gas Law both in Brazil and abroad. He is the founder and the editor in chief of PetroLaw website (https://petrolaw.wordpress.com/), which aims to spread knowledge and information on the Brazilian Oil and Gas Law. He holds a Law degree (JD equivalent) at the Pontifícia Universidade Católica do Rio de Janeiro (PUC-RJ), as well as certificates (diplomas) in Business Law and US Legal System from the University of California, San Diego, and in International Oil & Gas Law, Contracts and Negotiations from the Association of International Petroleum Negotiators – AIPN and the Rocky Mountain Mineral Law Foundation – RMMLF. André is also a member of the Association of International Petroleum Negotiators – AIPN and of the oil and gas committee of the Rio de Janeiro State Bar (OAB/RJ).

Dr. Wan Mohd Zulhafiz Wan Zahari is the Deputy Dean (Academic & Internationalisation) of Ahmad Ibrahim Kulliyyah (faculty) of Laws, International Islamic University Malaysia (IIUM) and the Company Secretary of IIUM. He is a qualified and experienced legal professional based in Malaysia. He completed his PhD in Law, specializing in oil and gas contracting at the University of Aberdeen in the United Kingdom. Furthermore, he holds a Master of Business Administration (MBA) in Energy Management from the University Technology of Petronas (UTP), a Master of Law (LLM) in Corporate Law from the University Technology of Mara (UiTM), and a Bachelor of Law (LLB)(Hons) from IIUM. For any inquiries or professional correspondence, Dr. Wan Zulhafiz can be reached via email at wzulhafiz@iium.edu.my.

Nurzhan Kakimov is legal counsel for Shell in Nur-Sultan, Kazakhstan. Before that, he was the legal manager for contracts for Karachaganak Petroleum Operating B.V. (KPO).

Reyhan Kamil is an account manager at Hilti Indonesia. Before that, he performed field analysis for Saka Energy Indonesia.